National Energy Board

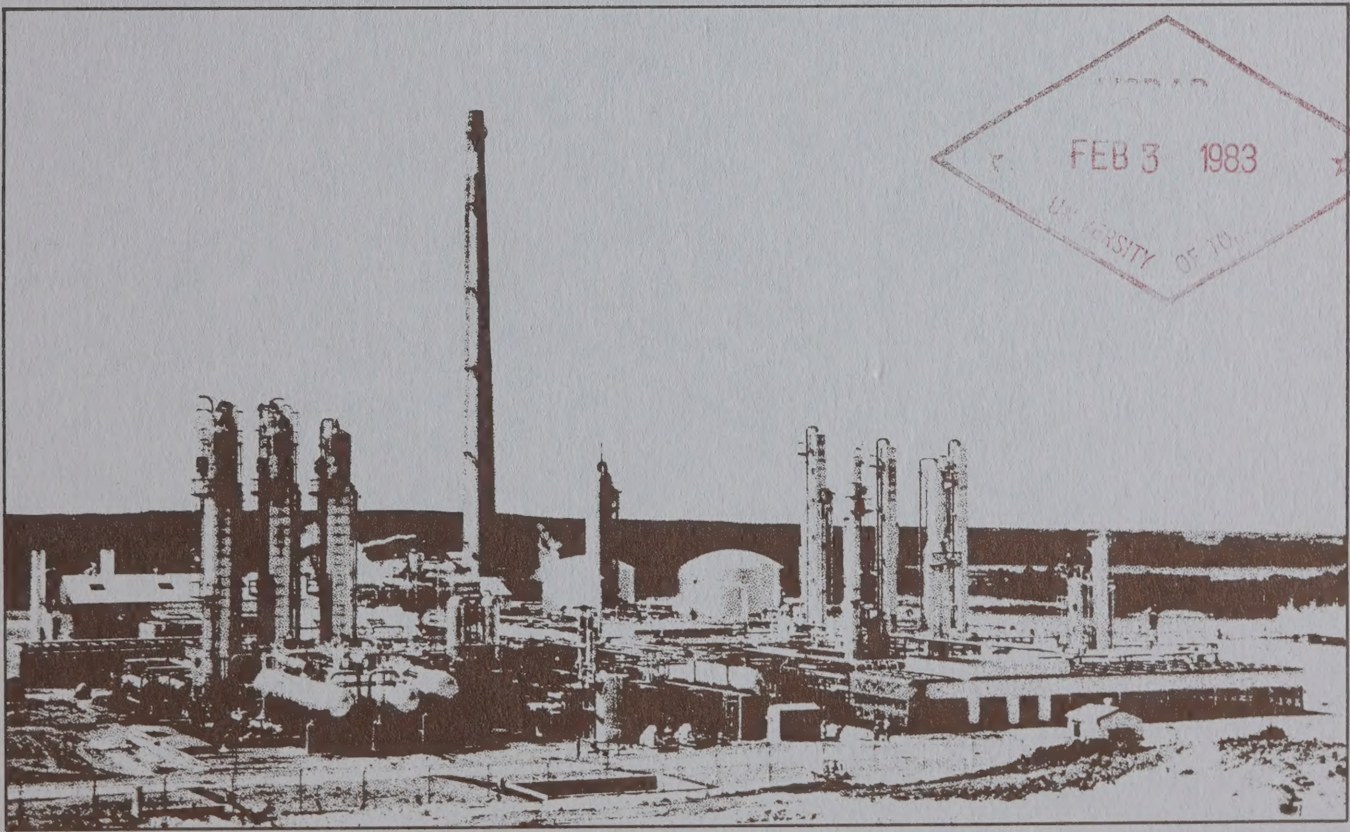
REASONS FOR DECISIONS
IN THE MATTER OF

Phase II – The Licence Phase and Phase III – The Surplus Phase

OF THE

Gas Export Omnibus Hearing, 1982

JANUARY 1983



NATIONAL ENERGY BOARD
Reasons for Decisions

In the Matter of
Phase II - The Licence Phase
and
Phase III - The Surplus Phase

of the

Gas Export Omnibus Hearing, 1982

and

In the Matter of Applications Under Part VI
of the National Energy Board Act

of

ALBERTA AND SOUTHERN GAS CO. LTD.
CANADIAN-MONTANA PIPE LINE COMPANY
CARTER ENERGY LIMITED
COLUMBIA GAS DEVELOPMENT OF CANADA LTD.
CONSOLIDATED NATURAL GAS LIMITED
DOME PETROLEUM LIMITED
KANNGAZ PRODUCERS LTD.
NIAGARA GAS TRANSMISSION LIMITED
OCELOT INDUSTRIES LTD.
PAN-ALBERTA GAS LTD.
PROGAS LIMITED
RIM GAS LTD.
SULPETRO LIMITED
TRANSCANADA PIPELINES LIMITED
TRANSCONTINENTAL GAS PIPE LINE CORPORATION
UNION GAS LIMITED
WESTCOAST TRANSMISSION COMPANY LIMITED

January 1983

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IN THE MATTER OF the National Energy Board Act and the Regulations made thereunder;

AND IN THE MATTER OF a review of existing natural gas licences and the Board's surplus determination procedures;

AND IN THE MATTER OF applications made by Pan-Alberta Gas Ltd., Sulpetro Limited and TransCanada PipeLines Limited for licences under Part VI of the National Energy Board Act for the export of natural gas to the United States of America;

AND IN THE MATTER OF applications made by Alberta and Southern Gas Co. Ltd., Pan-Alberta Gas Ltd. and TransCanada PipeLines Limited under Part VI of the National Energy Board Act to vary existing natural gas export licences.

LICENCE PHASE
SURPLUS PHASE

Heard in Ottawa, Ontario on 13, 14, 15, 19, 20, 21, 22, 26, 27, 28, 29 July, and 3, 4, 5, 9, 10, 11, 12, 16, 17, 18, 19, 23, 24, 25, 26 August, and 7, 8, 9, 13, 14, 15, 16, 20 September, and in Calgary, Alberta on 27, 28 September, and in Vancouver, British Columbia on 4 October and in Ottawa, Ontario on 15, 18, 19, 20, 21, 22, 25, 26, 27, 28, 29 October, and 1 November 1982.

BEFORE:

C.G. Edge	Presiding Member
R.B. Horner, Q.C.	Member
A.B. Gilmour	Member

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METRIC CONVERSION TABLE

1 cubic foot of natural gas (at 14.73 psia and 60°F)	=	0.028 327 84 cubic metres
1 cubic metre of natural gas	=	35.301 cubic feet
1 Btu 60/61	=	1 054.615 joules
1 Mcf (at 14.73 psia)	=	28.327 84 m^3
1 MMcf (at 14.73 psia	=	28 327.84 m^3 or 28.327 84 x $10^3 m^3$
1 Bcf	=	28 327 840 m^3 or 28.327 84 x $10^6 m^3$
1 x $10^3 m^3$	=	35.301 Mcf
1 x $10^6 m^3$	=	35.301 MMcf
1 x $10^9 m^3$	=	35.301 Bcf

APPROXIMATE EQUIVALENT VOLUMES OF NATURAL GAS

1 GJ	=	0.95 Mcf
1 TJ	=	0.95 MMcf
1 PJ	=	0.95 Bcf
1 EJ	=	0.95 Tcf

CHAPTER 1
Foreword

One of the key responsibilities of the National Energy Board is the licensing of exports of natural gas. Under its Act the Board is required to satisfy itself that the quantity of natural gas proposed to be exported does not exceed the surplus remaining after due allowance for the reasonably foreseeable requirements for use in Canada.

The Board has developed procedures over the years for determining the quantity of natural gas available for export. These procedures are described in some detail in Chapter 3, Surplus.

The question, "Why export natural gas at all?" is discussed in the Introduction to Chapter 4, Reasons for Decisions.

By December 1981 the Board had received sixteen applications for licences to export natural gas or to vary existing licences. The Board decided to consider these applications at a public hearing to be held in 1982.

In light of the rapidly changing conditions in the natural gas industry, the Board also judged it timely to review the continuing appropriateness of conditions attached to existing licences to export natural gas.

In addition, during its Inquiry into Canadian Energy Supply and Demand in 1980 and 1981, the Board had received representations that it should modify its procedures for determining the surplus of natural gas available for export. It appeared to the Board that it should review its surplus determination procedures in association with its hearing on export applications.

Accordingly, on 14 December 1981 the Board issued Order No. GH-6-81 setting down the Gas Export Omnibus Hearing, 1982. The Hearing Order and the Guidelines for the Preparation of Submissions are Appendix 1 to this Report.

The hearing was held in three phases:

- Phase I - The Review Phase
- Phase II - The Licence Phase
- Phase III - The Surplus Phase.

The Review Phase of the hearing was held in Ottawa from 16 March to 6 April 1982 inclusive. During Phase I the Board considered whether any changes should be made to the conditions of existing natural gas export licences and whether the protection procedures for licensed volumes should be changed. The Board also reviewed the procedure it used to determine the availability of surplus natural gas for export. It also considered other issues related to the terms and conditions of existing and future licences. Among these were whether annual averaging should be removed from licences and whether take-or-pay should be included.

In May 1982, the Board released its decision on Phase I. The Board decided not to make changes in existing export licences and it decided to adopt more flexible procedures for determining the amount of surplus natural gas in Canada available for export. The Board retained the 25A1 criteria (25 times the current year's demand) in its Reserves Formula but decided to base the allowance for exports under existing licences on maximum quantities exportable under existing licence conditions. Previously the remaining term quantity in the licence had been used. The Board also decided to use a Deliverability Appraisal as a guideline, rather than as a rigid test, to determine the annual quantities of gas surplus to foreseeable Canadian requirements. In the Deliverability Appraisal the Board decided to base the allowance for exports on estimated exports under existing licences.

The Board also decided that the additional flexibility afforded by annual averaging conditions would be desirable. Additionally the Board indicated that it would place considerable emphasis on the existence of reasonable take-or-pay provisions in export contracts, where such provisions were appropriate. The Board did not however, condition existing licences to include take-or-pay.

The Board recommended that amendments be made to its Part VI Regulations, which would require licence-holders to file copies of all changes and amendments to gas sales contracts and agreements between exporters and importers and which would prohibit any export of gas pursuant to these changes or amendments until the Board's approval had been obtained. The amendment was approved by Governor in Council on 21 October 1982.

The Board also recommended a further amendment to its regulations to allow it to authorize, by order, the export of natural gas for terms of up to two years. The total of all authorizations for any one year would be limited to three billion cubic metres. The necessary amendments to permit this

were subsequently approved by Governor in Council and came into effect on 18 November 1982.

Following the Phase I decision, the Board provided Applicants and other interested parties the opportunity to file new applications or amend existing applications or submissions to take account of the Board's decision.

By the opening of Phase II, the Licence Phase, on 13 July 1982, the Board had received twenty-nine applications for the issue of new licences or amendments to existing licences. All but three of these involved the export of natural gas to the United States; the others were for the export of liquefied natural gas (LNG) to Japan or Korea. Some one hundred interventions were received.

In Phase II, the Board examined the economic, contractual, regulatory, and other aspects of the individual applications. It also examined the markets for Canadian gas in the United States and Japan.

A summary of the applications considered at the hearing is contained in Chapter 2.

Phase III, the Surplus Phase of the hearing, commenced in Ottawa on 13 September, continued in Calgary on 27 September and Vancouver on 4 October, and reconvened in Ottawa on 15 October 1982.

During this phase the Board heard evidence on natural gas demand, supply, and surplus available for export.

On 9 August 1982, during Phase II of the hearing, Rim Gas Ltd. advised the Board that it wished its application for export of LNG to Japan to be placed in a "hearing pending" status and to receive no further consideration by the Board in the Gas Export Omnibus Hearing, 1982. On 12 August 1982, Carter Energy Limited made a similar request to the Board with respect to its application to export LNG to Japan and Korea.

The Board accepted the requests and, accordingly, no further consideration of the two proposals was given in these proceedings.

This report deals with Phases II and III of the Gas Export Omnibus Hearing, 1982. The applications before the Board are described in Chapter 2. Chapter 3 deals with natural gas supply, demand and surplus. The Board's Reasons for Decisions are set out in Chapter 4, while Chapter 5 lists the decisions with respect to individual applications.

CHAPTER 2
The Applications

2.1 Introduction

This Chapter provides a summary of the main elements of each application. The Board heard applications from 13 companies for new licences, and for amendments and/or extensions to existing licences for the export of natural gas to the United States and in the case of Dome's application, to export LNG to Japan. In addition, Union Gas applied for a licence to export SNG to the United States and Transco applied for an import/export licence for the movement of natural gas through Canada.

In total, the applications sought approval for the export of some 699.1 x $10^9 m^3$ (26.5 EJ). Figure 4-1 provides a map showing the pipeline systems through which the proposed quantities would flow to the various border points for export to the United States and to Japan.

The Applicants in Phase II were:

- Alberta and Southern
- Canadian-Montana
- Columbia
- Consolidated
- Dome
- KannGaz
- Niagara Gas
- Ocelot
- Pan-Alberta
- ProGas
- Sulpetro
- TransCanada
- Transco
- Union Gas
- Westcoast

2.2 Alberta and Southern

Alberta and Southern is a wholly-owned subsidiary of PG&E and the holder of gas export Licences GL-3, GL-16, GL-24 and GL-35. Alberta and Southern's gas is transported from Alberta through the facilities of ANG to a point on the international boundary at Kingsgate, British Columbia where it is sold to PGT which transports the gas to California for resale to PG&E.

Alberta and Southern applied to amend and extend Licences GL-16, GL-24 and GL-35 as follows:

Application and Term	Incremental Quantity		
	Daily ($10^3 m^3$)	Annual ($10^6 m^3$)	Term ($10^6 m^3$)
Extension to GL-16			
1 Nov.'89 to 31 Oct.'91	6 409.2	2 119.8	4 239.5
Amendment to GL-24			
1 Nov.'91 to 31 Oct.'93	2 849.8	943.3	1 886.6
Amendment to GL-35			
1 Nov.'85 to 31 Oct.'86	2 903.6	956.0	956.0
1 Nov.'86 to 31 Oct.'87	4 355.4	1 434.0	1 434.0
Extension to GL-35			
1 Nov.'87 to 31 Oct.'95	5 807.2	1 912.1	15 297.1

Alberta and Southern also applied for new licences to succeed Licences GL-3, GL-16, GL-24 and GL-35 as follows:

Application and Term	Incremental Quantity		
	Daily ($10^3 m^3$)	Annual ($10^6 m^3$)	Term ($10^6 m^3$)
To succeed GL-3			
1 Nov.'86 to 31 Oct. 2000	12 995.4	4 341.8	59 699.7
To succeed GL-16			
1 Nov.'91 to 31 Oct. 2000	6 409.2	2 119.8	19 078.0
To succeed GL-24			
1 Nov.'93 to 31 Oct. 2000	6 685.4	2 206.7	15 447.2
To succeed GL-35			
1 Nov.'95 to 31 Oct. 2000	5 807.2	1 912.1	9 560.6

Through its proposed licence amendments, extensions, and new licences, Alberta and Southern is seeking authority to export an additional 127 598.7 x $10^6 m^3$ of gas. The total for GL-3 reflects an adjustment made to reconcile the overlap in quantities for the period 31 October 1986 to 31 October 1987.

2.3 Canadian-Montana

Canadian-Montana is a wholly-owned subsidiary of Montana Power, a regulated public utility corporation incorporated under the laws of the State of Montana.

Canadian-Montana is the holder of Licences GL-5, GL-17, GL-25, and GL-53 authorizing exports at Cardston, Alberta, Emerson, Manitoba, and Niagara Falls, Ontario. Canadian-Montana is also authorized to export gas at Cardston and Aden, Alberta under Licences GL-36 and GL-52 respectively.

Canadian-Montana applied to amend existing Licences GL-25, GL-36 and GL-52 during the remaining licence terms ending 31 October 1993, 31 October 1987 and 31 December 1987 respectively. As well, it applied to extend the terms of Licences GL-17, GL-36 and GL-52 beyond their current expiry dates.

The effect of the proposed amendments and extensions on these Licences would be as follows:

Additional Quantities Under Existing Licences

Application and Term	Amended Licence Daily ($10^3 m^3$)	Amended Licence Annual ($10^6 m^3$)	Incremental Quantity Daily ($10^3 m^3$)	Incremental Quantity Annual ($10^6 m^3$)
Amendment to GL-25				
1 Nov.'82 to 31 Oct.'91	679.9	206.8	-	-
1 Nov.'91 to 31 Oct.'93	679.9	206.8	289.0	87.8
Amendment to GL-36				
1 Nov.'82 to 31 Oct.'85	339.9	103.4	-	-
1 Nov.'85 to 31 Oct.'86	339.9	103.4	169.9	51.7
1 Nov.'86 to 31 Oct.'87	339.9	103.4	254.9	77.5
Amendment to GL-52				
1 Jan.'83 to 31 Dec.'84	1 133.1	283.3	(283.3)	-
1 Jan.'85 to 31 Dec.'85	1 133.1	283.3	70.8	70.8
1 Jan.'86 to 31 Dec.'86	1 133.1	283.3	424.9	141.7
1 Jan.'87 to 31 Dec.'87	1 133.1	283.3	779.0	212.5
Extension to GL-17				
1 Nov.'89 to 31 Oct.'91	679.9	206.8	679.9	206.8
Extension to GL-36				
1 Nov.'87 to 31 Oct.'95	339.9	103.4	339.9	103.4
Extension to GL-52				
1 Jan.'88 to 31 Dec. 2000	1 133.1	283.3	1 133.1	283.3

In total, the additional term quantity applied for under existing licences is 5 653.5 x $10^6 m^3$.

In addition Canadian-Montana applied for four new licences to succeed Licences GL-5, GL-17, GL-25 and GL-36 as follows:

(a) a new licence to succeed Licence GL-5.

Term	Daily ($10^3 m^3$)	Annual ($10^6 m^3$)	Term ($10^6 m^3$)
1 Nov.'86 to 31 Oct. 2000	1 019.8	310.2	4 342.8

The term quantity applied-for includes 77.6 x $10^6 m^3$ currently authorized in existing Licence GL-5 during the period 31 October 1986 to 31 October 1987, the twenty-sixth year of Licence GL-5.

(b) a new licence to succeed Licence GL-17.

Term	Daily ($10^3 m^3$)	Annual ($10^6 m^3$)	Term ($10^6 m^3$)
1 Nov.'91 to 31 Oct. 2000	679.9	206.8	1 861.2

(c) a new licence to succeed Licence GL-25.

Term	Daily (10^3m^3)	Annual (10^6m^3)	Term (10^6m^3)
1 Nov.'93 to 31 Oct. 2000	679.9	206.8	1 447.6

(d) a new licence to succeed Licence GL-36.

Term	Daily (10^3m^3)	Annual (10^6m^3)	Term (10^6m^3)
1 Nov.'95 to 31 Oct. 2000	339.9	103.4	517.0

In summary Canadian-Montana has applied for a total incremental term quantity of 13 822.1 x 10^6m^3, consisting of licence amendments and extensions for 5 653.5 x 10^6m^3 and new licences for 8 168.6 x 10^6m^3.

Canadian-Montana applied for licence provisions authorizing both the continued and extended use of annual averaging.

2.4 Columbia

Columbia is the holder of Licence GL-54 which authorizes exports near Huntingdon, British Columbia for sale to Columbia Transmission via the Westcoast system. During Phase I of Omnibus '82, Columbia applied for and received Board approval to export at an additional export point near Monchy, Saskatchewan for delivery to Texas Gas off the Foothills system. Columbia's current application proposed that all exports authorized under Licence GL-54 be exported at Monchy for sale to Texas Gas.

Columbia will buy the gas it proposes to export at Monchy from Westcoast who will purchase the gas from Pan-Alberta under its existing Worsley and Pouce Coupe contracts. Columbia will sell Westcoast equivalent volumes of gas from the Kotaneelee field in the Yukon Territory. These arrangements would result in the export of Alberta gas currently moving into British Columbia and its replacement by Yukon Territory gas.

Columbia applied to amend Licence GL-54 and to extend the term approximately ten years to 31 October 1997. Commencing 1 November 1982, Columbia proposed to export the following daily and annual quantities:

Term	Amended Licence		Incremental Quantity	
	Daily (10^3m^3)	Annual (10^6m^3)	Daily (10^3m^3)	Annual (10^6m^3)
Amendment				
1 Nov.'82 to 31 Oct.'84	1 450.0	517.0	-	93.5
1 Nov.'84 to 31 Oct.'85	1 450.0	517.0	617.2	240.8
1 Nov.'85 to 31 Oct.'86	1 450.0	517.0	894.8	332.8
1 Nov.'86 to 31 Oct.'87	1 450.0	517.0	1 172.4	424.9
Extension				
1 Nov.'87 to 31 Oct.'97	1 450.0	517.0	1 450.0	517.0

The incremental term quantity under the proposed amendment and extension would be 6 355.5 x 10^6m^3, which total does not reflect any credit from trapped gas as contained in Columbia's application.

In addition, Columbia applied for an annual averaging provision and an operating tolerance of two percent.

2.5 Consolidated

Consolidated is a wholly-owned subsidiary of Northern Natural. Consolidated is the holder of Licence GL-61 for the sale of gas to Northern Natural at Emerson, Manitoba and Monchy, Saskatchewan.

Consolidated applied to:

- amend Licence GL-61 by increasing the daily and annual quantities in the years 1984 through 1987. The proposed amendment would provide Consolidated with the means to recover undelivered licensed quantities from the 1980-81 licence year;
- extend GL-61 two years beyond its current expiry date to 31 October 1989. The Company proposed that the extended quantities would be split equally between the Emerson and Monchy delivery points.

The gas to be exported would be transported by Foothills to Monchy and by TransCanada to Emerson.

The effect Consolidated's proposed amendment and extension would have on Licence GL-61 would be as follows:

Term	Amended Licence Daily (10^3m^3)	Amended Licence Annual (10^6m^3)	Incremental Quantity Daily (10^3m^3)	Incremental Quantity Annual (10^6m^3)
Amendment				
1 Nov.'84 to 31 Oct.'85	5 665.6	2 068.0	1 416.4	517.0
1 Nov.'85 to 31 Oct.'86	4 532.6	1 654.0	1 699.8	620.0
1 Nov.'86 to 31 Oct.'87	3 824.3	1 396.0	2 408.0	879.0
Extension				
1 Nov.'87 to 31 Oct.'88	3 824.4	1 396.0	3 824.4	1 396.0
1 Nov.'88 to 31 Oct.'89	3 824.4	1 396.0	3 824.4	1 396.0

The term quantity under the proposed amendment and extension would increase by 4 808.0 x 10^6m^3.

2.6 Dome

Dome applied for a licence to export LNG to Japan from a facility to be located near Prince Rupert, British Columbia. The licence term would be for 19 years and six months from 1 April 1986 to 30 September 2005. The applied-for quantity is as follows:

Term	Annual (10^6m^3)
1 Apr.'86 to 31 Dec.'86	2 258.0
1 Jan.'87 to 31 Dec.'87	3 309.0
1 Jan.'88 to 31 Dec.'88	3 986.0
1 Jan.'89 to 31 Dec.'89	4 136.0
1 Jan.'90 to 31 Dec. 2004	4 362.0
1 Jan. 2005 to 30 Sept. 2005	3 309.0

Total term quantity applied for is 82 428.0 x 10^6m^3.

Dome applied for a ten percent operating tolerance and a provision to allow for an extension to the licence term to enable Dome to deliver quantities not taken during the term of the licence.

The proposed owners of the project are Dome and NIC Resources Inc., a wholly-owned subsidiary of Nissho Iwai.

The gas supply for the project would come from various fields in Alberta and British Columbia. The gas would be transported by Westcoast to the LNG plant through a proposed new pipeline. The gas would be liquefied and carried by ocean transport to Japan.

2.7 KannGaz

KannGaz is under the ownership and control of a group of independent Canadian oil and gas exploration companies.

KannGaz applied for a 15-year licence to export gas from 1 November 1983 to 31 October 1998. The applied-for quantity is as follows:

Term	Daily (10^3m^3)	Annual (10^6m^3)
1 Nov.'83 to 31 Oct.'98	3 540.0	1 292.1

The term quantity applied for is 19 381.5 x 10^6m^3.

KannGaz included a request for a 15 percent operating tolerance and annual averaging.

The gas to be exported would be transported by TransCanada from Alberta to Niagara Falls, Ontario for sale to Tennessee Gas.

2.8 Niagara Gas

Niagara Gas applied to combine the existing authorized licence quantities under Licences GL-6 and GL-55 in one licence, GL-55, and to extend the term of the revised single licence by eight years to 31 October 1995. When the amended Licence GL-55 becomes effective as requested, Niagara Gas indicated that it would consent to a revocation of Licence GL-6.

The effect of the proposed amendment and extension on Licence GL-55 would be as follows:

Term	Amended Licence Daily (10^3m^3)	Amended Licence Annual (10^6m^3)	Incremental Quantity Daily (10^3m^3)	Incremental Quantity Annual (10^6m^3)
Amendment				
1 Nov.'82 to 31 Oct.'84	1 200.0	250.0	850.0	160.9
1 Nov.'84 to 31 Oct.'85	1 200.0	250.0	937.5	183.2
1 Nov.'85 to 31 Oct.'86	1 200.0	275.0	600.0	138.2
1 Nov.'86 to 31 Oct.'87	1 200.0	275.0	900.0	206.6
Extension				
1 Nov.'87 to 31 Oct.'95			1 200.0	275.0

The incremental term quantity applied for is 3 049.8 x 10^6m^3 less an allowance for Licence GL-6 quantities. The net increase is 2 290.7 x 10^6m^3.

Niagara applied for a ten percent tolerance in order to allow for make-up of quantities not delivered due to temporary operating difficulties.

2.9 Ocelot

Ocelot applied for a licence to export gas produced in the Province of Saskatchewan for a 16-year period from 1 November 1985 to 31 October 2001. Ocelot applied for the following quantities:

Term	Daily (10^3m^3)	Annual (10^6m^3)
1 Nov.'85 to 31 Oct.'86	708.0	258.4
1 Nov.'86 to 31 Oct. 2001	2 833.0	1 034.0

The term quantity applied for is 15 768.4 x 10^6m^3.

The gas proposed for export would be transported by TransCanada from Saskatchewan to Niagara Falls, Ontario for sale to Tennessee Gas.

2.10 Pan-Alberta

Pan-Alberta is the holder of Licences GL-58 and GL-62 for exports through the Foothills system at Monchy, Saskatchewan. Pan-Alberta also holds Licences GL-59 and GL-63 for exports via the Foothills system at Kingsgate, British Columbia. The gas is sold at both delivery points to Northwest Alaskan.

(a) Application to Extend Exports Via The Alaska Highway Gas Pipeline.

Pan-Alberta applied to amend and extend Licences GL-58 and GL-59 and to amend Licence GL-63.

(i) GL-58

The proposed amendment to Licence GL-58 would convert the existing conditional or make-up quantities authorized for licence years 1986-87 and 1987-88 to firm quantities.

Pan-Alberta also applied to extend GL-58 seven years beyond its current expiry date of 31 October 1988, to 31 October 1995. For the 1994-95 licence year, Pan-Alberta applied for an annual quantity equal to 8 294.4 x 10^6m^3, less the quantity of gas actually exported during 1981-82.

The effect of the proposed amendment and extension on Licence GL-58 would be as follows:

Term	Amended Licence Daily (10^3m^3)	Amended Licence Annual (10^6m^3)	Incremental Quantity Daily (10^3m^3)	Incremental Quantity Annual (10^6m^3)
Amendment				
1 Nov.'86 to 31 Oct.'87	19 837.2	6 600.4	13 605.1	4 526.8
1 Nov.'87 to 31 Oct.'88	24 928.5	8 294.4	24 928.5	8 294.4
Extension				
1 Nov.'88 to 31 Oct.'94	24 928.5	8 294.4	24 928.5	8 294.4

For the 1994-95 licence year, Pan-Alberta has requested that the annual quantity shall be 8 294.4 x 10^6m^3 less the quantity of gas actually exported during 1981-82.

The total incremental term quantity for GL-58 would be 62 587.6 x 10^6m^3.

(ii) GL-59

The proposed amendment to Licence GL-59 sought to convert the existing conditional quantity contained in the Licence to a firm quantity during the 1987-88 licence year.

The Applicant also applied to extend GL-59 six years beyond its current expiry date of 31 October 1988, to 31 October 1994.

The effect of the proposed amendment and extension of Licence GL-59 would be as follows:

Term	Amended Licence Daily (10^3m^3)	Amended Licence Annual (10^6m^3)	Incremental Quantity Daily (10^3m^3)	Incremental Quantity Annual (10^6m^3)
Amendment				
1 Nov.'87 to 31 Oct.'88	7 478.6	2 488.3	7 478.6	2 488.3
Extension				
1 Nov.'88 to 31 Oct.'93	7 478.6	2 488.3	7 478.6	2 488.3

For the period 1 November 1993 to 31 October

1994, Pan-Alberta requested that the annual quantity be equal to 2 488.3 x $10^6 m^3$ less the quantity of gas actually exported during 1980-81.

The total incremental term quantity for GL-59 would be 14 929.8 x $10^6 m^3$.

(iii) GL-63

Pan-Alberta applied to amend Licence GL-63, but requested that the amendment only take effect if the proposed amendment and extension to Licence GL-59 were approved. The amendment to GL-63 sought to reduce the existing daily, annual and term quantities of the Licence and to remove the conditional clause subjecting the 1985-86 and 1986-87 licence quantities to Canadian deliverability requirements. The proposed amendment would be as follows:

Term	Amended Licence Daily ($10^3 m^3$)	Amended Licence Annual ($10^6 m^3$)	Decrease Daily ($10^3 m^3$)	Decrease Annual ($10^6 m^3$)
1 Nov.'80 to 31 Oct.'83	931.5	340.0	-	-
1 Nov.'83 to 31 Oct.'84	1 869.7	622.1	-	-
1 Nov.'84 to 31 Oct.'85	1 869.7	622.1	1 869.7	622.1
1 Nov.'85 to 31 Oct.'86	3 739.3	1 244.1	1 869.7	622.1
1 Nov.'86 to 31 Oct.'87	5 609.6	1 866.2	1 869.0	622.1

The decrease of term quantity for GL-63 would be 1 866.3 x $10^6 m^3$.

(b) Application to Export to the New England and Mid-Atlantic States.

Pan-Alberta applied for a new licence to export gas to the New England and Mid-Atlantic States commencing 1 November 1984 and ending 31 October 2000.

Term	Daily ($10^3 m^3$)	Annual ($10^6 m^3$)
1 Nov.'84 to 31 Oct. 2000	8 665.0	3 162.7

The term quantity applied for is 50 603.2 x $10^6 m^3$.

Pan-Alberta also requested a two percent operating tolerance.

The gas to be exported would be transported from Alberta to Niagara Falls, Ontario by TransCanada for delivery in equal shares to three United States companies. These are Algonquin Gas, Texas Eastern and Transco.

2.11 ProGas

ProGas is the holder of Licence GL-56 for the export of gas at Emerson, Manitoba and Monchy, Saskatchewan to four United States buyers. These are Texas Eastern, Michigan Wisconsin, Natural Gas Pipe and Tennessee Gas. ProGas applied for an amendment and extension to GL-56 and for a new export licence.

(a) Application to Amend and Extend Licence GL-56

ProGas applied to amend Licence GL-56 by increasing the daily and annual quantities in the three licence years 1984-85, 1985-86 and 1986-87 and to extend the Licence two years beyond its current expiry date of 31 October 1987.

The effect of the proposed amendment and extension on Licence GL-56 would be as follows:

Term	Amended Licence Daily ($10^3 m^3$)	Amended Licence Annual ($10^6 m^3$)	Incremental Quantity Daily ($10^3 m^3$)	Incremental Quantity Annual ($10^6 m^3$)
Amendment				
1 Nov.'82 to 31 Oct.'84	9 440.9	3 100.0	-	-
1 Nov.'84 to 31 Oct.'85	9 440.9	3 100.0	2 352.2	775.0
1 Nov.'85 to 31 Oct.'86	7 552.7	2 480.0	2 832.3	930.0
1 Nov.'86 to 31 Oct.'87	5 664.5	1 860.0	3 304.3	1 085.0
Extension				
1 Nov.'87 to 31 Oct.'88	3 776.4	1 240.0	3 776.4	1 240.0
1 Nov.'88 to 31 Oct.'89	1 888.2	620.0	1 888.2	620.0

The total incremental term quantity resulting from the amendment and extension is 4 650.0 x $10^6 m^3$. However, as a result of previously undelivered quantities due to regulatory delays and changes to sales contracts, ProGas has requested an increase in the term quantity of only 410.0 x $10^6 m^3$.

The gas to be exported would be transported by TransCanada to Emerson, Manitoba and by Foothills to Monchy, Saskatchewan.

(b) Application for a New Export Licence

ProGas applied for a new licence to export gas at Niagara Falls, Ontario, to Texas Eastern; at Emerson, Manitoba to Texas Gas and at Kingsgate, British Columbia to Transwestern. The licence would be for a period of 15 years commencing 1 November 1983 and ending 31 October 1998. The applied-for quantity is as follows:

	Daily (10^3m^3)	Annual (10^6m^3)
Sale to Texas Eastern	2 830.0	1 033.0
Sale to Texas Gas	5 270.0	1 923.6
Sale to Transwestern	1 870.0	682.6
Total Licence Quantity	9 970.0	3 639.2

The term quantity applied for is 54 588.0 x 10^6m^3.

As part of its application ProGas requested a two percent operating tolerance and a provision to allow for the extension of the licence term one year in order to remove quantities of gas paid for but not taken.

The quantities ProGas proposed to sell to Texas Eastern at Niagara Falls, Ontario and to Texas Gas at Emerson, Manitoba would be transported through the facilities of TransCanada. The gas for Transwestern would be delivered to Kingsgate, British Columbia by Foothills.

2.12 Sulpetro

Sulpetro is the holder of Licence GL-57 for the sale of gas to Transco at Niagara Falls, Ontario. Licence GL-57 expires 31 October 1983.

Sulpetro applied for a new eight-year licence commencing 1 November 1983 and ending 31 October 1991. The proposed new licence would replace existing Licence GL-57.

Sulpetro applied for the following quantities:

Term	Daily (10^3m^3)	Annual (10^6m^3)
1 Nov.'83 to 31 Oct.'87	2 125.0	775.6
1 Nov.'87 to 31 Oct.'88	2 125.0	620.5
1 Nov.'88 to 31 Oct.'89	2 125.0	465.4
1 Nov.'89 to 31 Oct.'90	2 125.0	310.3
1 Nov.'90 to 31 Oct.'91	2 125.0	155.1

The term quantity applied for is 4 653.7 x 10^6m^3.

Sulpetro included a request for the right to recover annual quantities not taken in one year during any of the following four years during the term of the licence subject always to the maximum daily limitation. The Applicant also applied for a ten percent operating tolerance.

The gas proposed for export would be transported from Alberta to Niagara Falls, Ontario by TransCanada.

2.13 TransCanada

TransCanada operates a pipeline system extending from the Province of Alberta through the Provinces of Saskatchewan, Manitoba, and Ontario to the Province of Quebec. TransCanada currently delivers gas to various United States buyers at Emerson, Manitoba, and Phillipsburg, Quebec under Licences GL-18, GL-19, GL-20, GL-37, GL-38, GL-39, GL-43 and GL-60. TransCanada is also authorized to export interruptible quantities under Licence GL-18 at Niagara Falls, Ontario.

TransCanada applied for eight new export licences. Within each licence application TransCanada has requested:

a) a make-up condition equal to ten percent of the maximum daily quantity but subject to the available facility capacity and the maximum annual quantities in the licence;

b) a two percent operating tolerance;

c) a one-year make-up condition that would allow recovery of any undelivered term quantity at the expiry of the licence subject to the remaining term and maximum daily quantities contained in the licence.

The eight new export licences which TransCanada applied for are as follows:

(a) Application for Export to Boundary Gas

TransCanada applied for a new licence to export of gas to Boundary Gas at Niagara Falls, Ontario for a ten-year term commencing 1 November 1984 and ending 31 October 1994. The quantity applied for is as follows:

Term	Daily (10^3m^3)	Annual (10^6m^3)
1 Nov.'84 to 31 Oct.'94	5 240.7	1 918.1

The term quantity applied for is 19 144.1 x 10^6m^3.

(b) Application for Export to Tennessee Gas (Tennessee #1).

TransCanada applied for a new licence for the export of gas to Tennessee Gas at Niagara Falls, Ontario. The duration of the licence would be for a term of ten years commencing 1 November 1984 and ending 31 October 1994. The quantity applied for is as follows:

Term	Daily (10^3m^3)	Annual (10^6m^3)
1 Nov.'84 to 31 Oct.'94	2 832.8	1 036.8

The term quantity applied for is 10 348.2 x 10^6m^3.

(c) Application for Export to Tennessee Gas (Tennessee #2).

TransCanada applied for a new licence to export gas to Tennessee Gas at Niagara Falls, Ontario. The duration of the licence would be for a ten-year term commencing 1 November 1984 and ending 31 October 1994. The quantity applied for is as follows:

Term	Daily (10^3m^3)	Annual (10^6m^3)
1 Nov.'84 to 31 Oct.'94	5 665.6	2 073.6

The term quantity applied for is 20 696.4 x 10^6m^3.

(d) Application for Export to Natural Gas Pipe

TransCanada applied for a new licence to export gas to Natural Gas Pipe at Emerson, Manitoba for a 15-year term commencing 1 November 1984 and ending 31 October 1999. The quantity applied for is as follows:

Term	Daily (10^3m^3)	Annual (10^6m^3)
1 Nov.'84 to 31 Oct.'99	2 832.8	1 036.8

The term quantity applied for is 15 518.1 x 10^6m^3.

(e) Application for Export to Michigan Wisconsin

TransCanada applied for a new licence for the export of gas to Michigan Wisconsin for 15 years commencing 1 November 1984 and ending 31 October 1999. Deliveries to Michigan Wisconsin would be at Emerson, Manitoba. The quantity applied for is as follows:

Term	Daily (10^3m^3)	Annual (10^6m^3)
1 Nov.'84 to 31 Oct. '99	2 832.8	1 036.8

The term quantity applied for is 15 518.1 x 10^6m^3.

(f) Application for Export to Transco

TransCanada applied for a new licence to export gas to Transco at Emerson, Manitoba and/or Niagara Falls, Ontario. The licence term would commence 1 November 1984 for a 15-year period, expiring 31 October 1999. The quantity applied for is as follows:

Term	Daily (10^3m^3)	Annual (10^6m^3)
1 Nov.'84 to 31 Oct.'99	8 498.4	3 110.4

The term quantity applied for is 46 554.2 x 10^6m^3.

The gas TransCanada proposed to export under this licence to Transco is the subject matter of Transco's application for a licence to import at Sarnia, Ontario for re-export at Niagara Falls, Ontario. (See the Transco application summary 2.14)

(g) Application for Export to Midwestern Gas

TransCanada applied for a new licence to export gas to Midwestern. TransCanada currently holds export Licence GL-60 authorizing the sale to Midwestern of 6 317.1 x 10^3m^3 per day and an average of 2 096.3 x10^6m^3 per year for the period ending 31 October 1984. During the period 1 November 1984 to 14 December 1985 the authorized daily and annual quantities are scheduled to decrease to a low of 3 158.6 x 10^3m^3 per day and 1 711.2 x 10^6 m^3 for the period.

The Applicant's proposed new licence would replace GL-60 and is for the following quantity:

Term	Daily (10^3m^3)	Annual (10^6m^3)
1 Nov.'84 to 31 Oct.'85	6 317.1	2 096.3
1 Nov.'85 to 31 Oct.'99	6 317.1	2 096.3

The term quantity applied for is 29 733.2 x 10^6m^3.

(h) Application for Export to Texas Eastern

TransCanada applied for a new licence to export

gas to Texas Eastern at Niagara Falls, Ontario for a 14-year term commencing 1 November 1985 and ending 31 October 1999. The quantity applied for is as follows:

Term	Daily (10^3m^3)	Annual (10^6m^3)
1 Nov.'85 to 31 Oct.'99	2 832.8	1 036.8

The term quantity applied for is 14 484.1 x 10^6m^3.

2.14 Transco

Transco is a company incorporated pursuant to the laws of the State of Delaware in the United States. Transco operates a major interstate gas transmission system extending from the State of Texas to New York State.

Transco currently imports Canadian gas from Union Gas at Windsor, Ontario and from Sulpetro at Niagara Falls, Ontario.

Transco applied for a 20-year licence commencing 1 November 1984 to import gas into Canada at Sarnia, Ontario and to export a like annual quantity at Niagara Falls, Ontario. The proposal involves the use of storage in Michigan and in Ontario.

The gas in question will be purchased from TransCanada which has applied for a 15-year licence to export up to 8 498.4 x 10^3m^3 per day at Emerson and/or Niagara Falls for sale to Transco.

Transco would take delivery of some 1 133.1 x 10^6m^3 per year from TransCanada at Emerson, Manitoba for transmission through the Great Lakes pipeline. A like quantity of Canadian gas would be displaced onto TransCanada's central section for delivery to the Toronto load centre. Approximately one-half of the quantities exported at Emerson would be delivered by Great Lakes to Crawford, Michigan for injection into the storage facilities of ANR. The remaining portion of the quantities would be delivered by Great Lakes to Sarnia for import by Transco.

From Sarnia the quantities would move through the pipeline facilities of TransCanada and Union Gas to Dawn, Ontario for injection into Union Gas storage. This storage arrangement would only be effective up to the total annual quantity of 566.6 x 10^6m^3 per year.

During times when Transco would require storage withdrawals, Great Lakes would transport up to 8 498.4 x 10^3m^3 per day from ANR storage in Michigan to Sarnia for delivery to TransCanada. TransCanada would move the gas to Union Gas transmission facilities and Union Gas would move the gas through its facilities and add it to withdrawals from Union Gas storage for delivery to TransCanada near Kirkwall, Ontario. TransCanada would then move these total quantities to Niagara Falls for delivery to Transco.

While the Transco application contemplates identical annual volumes of imports and re-exports on a winter daily basis, proposed exports can be at a level twice that for imports, the additional amount of exports consisting of withdrawals from Ontario storage. In addition, the obligation upon TransCanada to export to Transco at Niagara Falls can increase the daily level of exports in the winter to three times the level of imports.

Since the Transco scheme involves importing and re-exporting like annual volumes, there are no net annual or term volume exports associated with its application.

2.15 Union Gas

Union Gas is a public utility which owns and operates gas transmission, distribution and storage facilities in the Province of Ontario. It is the holder of Licence GL-64 for the sale of methane-rich synthetic natural gas (SNG) by displacement to Transco at Windsor, Ontario. Union Gas purchases this SNG from Petrosar at Sarnia, Ontario.

Union Gas applied for an extension to the term of its existing Licence GL-64 from its current expiry date of 31 October 1985 to 30 April 1993 with provision to allow for, if necessary, an additional year to 30 April 1994 to permit recovery of gas paid for but not taken.

The proposed extension would be at existing licence levels as follows:

Term	Daily (10^3m^3)	Annual (10^6m^3)
1 Nov.'85 to 30 April'93	1 100.0	284.0

The incremental term quantity would be 2 130.0 x 10^6m^3.

2.16 Westcoast

Westcoast is engaged in the purchase of natural gas in the Provinces of Alberta and British Columbia, and in the Yukon and Northwest Territories. Westcoast is also engaged in the gathering, processing, and transmission of natural gas in

Canada for sale to markets in British Columbia and in the United States.

Westcoast is the holder of Licence GL-4 authorizing exports at Kingsgate, British Columbia. As well, Westcoast holds Licence GL-41 authorizing exports at Huntingdon, British Columbia and Monchy, Saskatchewan. The natural gas exported at Huntingdon and Kingsgate is sold to Northwest Pipeline. Exports at Monchy are delivered to Texas Gas. Monchy quantities are displaced from Pan-Alberta deliveries to Westcoast from the Worsley and Pouce Coupe contracts.

Westcoast applied to amend Licence GL-41 during the remaining term by adding Kingsgate as an additional export point and by increasing the daily, annual and term quantities. As well, it applied to extend the term seven years to 31 October 1996. Commencing 1 November 1982, Westcoast proposed to export the following daily and annual quantities:

Additional Quantities Under the Existing Licence

Term	Amended Licence Daily (10^3m^3)	Amended Licence Annual (10^6m^3)	Incremental Quantity Daily (10^3m^3)	Incremental Quantity Annual (10^6m^3)
Amendment				
At Huntingdon and Kingsgate:				
1 Nov.'82 to 31 Oct.'89	26 039.0 (1)	8 067.8 (1)	141.7	97.5
Extension				
At Huntingdon and Kingsgate:				
1 Nov.'89 to 31 Oct.'92	20 813.0	7 222.0	20 813.0	7 222.0
1 Nov.'92 to 31 Oct.'95	17 981.0	6 230.0	17 981.0	6 230.0
1 Nov.'95 to 31 Oct.'96	16 282.0	5 663.0	16 282.0	5 663.0
At Monchy:				
1 Nov.'89 to 31 Oct.'96	1 416.4	517.0	1 416.4	517.0

(1) Of these quantities Westcoast proposes to export a daily quantity of 1 416.4 x 10^3m^3 and an annual quantity of 517.0 x 10^6m^3 at Monchy.

The term quantity under the proposed amendment and extension of Licence GL-41 would increase by 50 320.5 x 10^6m^3 to 179 253.2 x 10^6m^3, including 13 920.3 x 10^6m^3 of natural gas which the Applicant identified as being unexportable or trapped gas as at 31 October 1989 owing to existing licence conditions.

In addition, Westcoast applied for a new three-year licence as follows:

Additional Quantities Under The New Licence

Term	Daily (10^3m^3)	Annual (10^6m^3)
At Huntingdon and Kingsgate:		
1 Nov.'96 to 31 Oct.'99	16 282.0	5 663.0
At Monchy:		
1 Nov.'96 to 31 Oct.'97	1 416.4	517.0

The term quantity applied for under the new licence is 17 506.0 x 10^6m^3.

Westcoast applied for licence provisions authorizing both the continued and extended use of annual averaging and authorizing it to exceed the maximum daily quantity in the licence.

In summary, the total new quantities applied for are:

Designation	Additional Term Quantity (10^6m^3)
Additional Term Quantity Under the Existing Licence:	50 320.5
Additional Term Quantity Under the New Licence:	17 506.0
Total:	67 826.5

CHAPTER 3
Surplus

Introduction

In its disposition of an application to export natural gas, the Board may issue a licence only if it has first satisfied itself that the quantity of gas to be exported is surplus to the reasonably foreseeable requirements for use in Canada, having regard to the trends in the discovery of gas in Canada. Such licences require Governor in Council approval before taking effect. The Board also makes allowance for exports authorized under existing licences.

In its report on Phase I of this Hearing the Board described new procedures it had adopted to determine the quantity of natural gas surplus and available for export. It was decided that surplus would be assessed by using a Reserves Formula and a Deliverability Appraisal.

In order to assess whether there is a surplus of natural gas the Board, in Phase III of the Hearing, received evidence regarding the supply of gas in Canada from established reserves and from reserves additions, the demand for gas in Canada, exports under existing licences, and surplus. The Board's conclusions on these matters follow.

3.1 Supply

3.1.1 Established Reserves

Estimates of remaining established reserves in Canada's conventional areas were provided by sixteen submittors. Estimates were as of 31 December 1981, with the exception of Petro-Canada, which estimated as of 31 December 1980. All estimates are compared in Table 3-1. Thirteen submittors provided a breakdown of remaining established reserves by region while the remaining three provided estimates for Canada in total. The majority of these estimates were based upon those of provincial regulatory agencies, NEB, and CPA. AERCB did not submit an estimate, but for comparative purposes the Board has included in Table 3-1 the estimate given in AERCB Report 82-18. Amoco identified 7.7 EJ of natural gas in Alberta, primarily in the Grande Prairie area, which it believed had not yet been accounted for by the AERCB, NEB or CPA and therefore added it to the CPA estimate for purposes of its submission. The Board has examined Amoco's evidence in this regard, and is not persuaded that additional established reserves should be recognized in this area at this time since the ability of very low permeability strata in the Alberta Deep Basin to produce gas at economic rates has not been satisfactorily demonstrated.

The Board's estimate of the remaining established reserves of marketable natural gas in conventional areas based on individual pool analyses is 80.8 EJ as of 31 December 1981, a net increase of 4.8 EJ over the Board's estimate for 31 December 1980. The Board's estimates of remaining established reserves by region are included in Table 3-1.

3.1.2 Reserves Additions and Ultimate Potential

Forecasts of reserves additions for the period 1982-2000 for all or portions of the conventional areas were provided by thirteen submittors. Amoco, Consolidated, Gulf and NOVA each submitted two forecasts. Forecasts of reserves additions are compared in Table 3-2.

The Board recognizes that the subjective nature of forecasts of reserves additions has led to divergent views, due to each submittor's perception of such variables as economic factors, drilling activity, ultimate potential, and market conditions.

Many submittors addressed the question of the effect of economic factors on gas reserves additions. It was felt that since natural gas exports are a major source of cash flow to the producing industry, the higher the level of additional exports the greater the availability of funds to producers for reinvestment. Increased exports would affect reserves additions by creating higher levels of drilling activity; however, few submittors attempted to quantify future levels of drilling activity.

Having considered the views of submittors, the Board has adopted a forecast of reserves additions to the year 2000 of 44.5 EJ. This is based on an ultimate potential of 183 EJ and a higher forecast of drilling activity than was used in the Board's June 1981 Report. Based on market opportunities that result from this Decision the Board believes it reasonable to assume drilling activity will return to the 1981 level by 1985. This rate is assumed to remain constant to the end of the forecast period.

A summary of the Board's forecast of annual reserves additions by region is given in Table 3-3.

Estimates of ultimate potential, like those of reserves additions, tend to differ considerably because of their subjective nature. Estimates

Table 3-1

REMAINING ESTABLISHED RESERVES OF MARKETABLE NATURAL GAS

CONVENTIONAL AREAS

COMPARISON OF ESTIMATES

31 December 1981

(Exajoules)

	B.C.	Alta.	Sask.	Southern Territories	Eastern Canada	Canada Total
AERCB	-	69.7	-	-	-	-
Amoco	8.6	74.6	1.3	0.5	0.3	85.3
A&S	9.3	69.7	1.4	0.3	0.3	81.0
Consolidated	9.5	69.7	1.2	0.4	0.3	81.1
CPA	8.6	66.9	1.3	0.5	0.3	77.6
Dome	9.3	69.7	1.2	0.3	0.3	80.8
Esso	8.8	70.3	1.4	0.5	0.1	81.1
Gulf	8.1	69.7	1.3	0.5	0.3	79.9
IPAC	9.3	69.7	1.4	0.3	0.3	81.0
KannGaz	9.3	69.7	1.1	0.7	0.3	81.1
NOVA	-	-	-	-	-	80.6
Norcen	-	-	-	-	-	79.0
Ocelot	8.3	66.2	1.1	0.3	0.3	76.2
Pan-Alberta	9.6	69.7	1.2	0.4	0.3	81.2
Petro-Canada	8.9	69.7	1.5	0.4	0.3	80.8
ProGas	9.3	69.7	1.1	0.3	0.3	80.7
Shell	8.6	66.9	1.3	0.5	0.3	77.6
TCPL	-	-	-	-	-	82.3
NEB	9.5	68.9	1.7	0.4	0.3	80.8

Gross heating values applicable to NEB estimate:

B.C.	38.8 MJ/m^3
Alberta	38.8 MJ/m^3
Saskatchewan	36.8 MJ/m^3
S. Territories	36.8 MJ/m^3

Table 3-2

MARKETABLE NATURAL GAS RESERVES ADDITIONS FORECASTS

CONVENTIONAL AREAS

COMPARISON OF ESTIMATES

1982-2000

(Exajoules)

	B.C.	Alta.	Sask.	Southern Territories	Eastern Canada	Canada Total
Amoco						
Base	5.4	41.2	1.4(1)	-	-	48.0
Expanded	8.4	69.3	1.4(1)	-	-	79.1
A&S	-	-	-	-	-	33.6
Consolidated						
Current	-	-	-	-	-	58.9
Improved	-	-	-	-	-	78.1
CPA	5.4	41.2	0.7	0.7	-	48.0
Dome	10.0	52.0	1.0	-	-	63.0
Esso	6.8	49.8	0.4	0.4	-	57.4
Gulf						
Base	6.6	36.3	0.2	-	0.2	43.3
Low	5.4	31.7	0.2	-	0.2	37.5
IPAC	-	-	-	-	-	42.6
NOVA						
Base	8.2	45.6	-	-	-	53.8
Incentive	8.2	56.4	-	-	-	64.6
Norcen	-	-	-	-	-	50.7
Pan-Alberta	-	-	-	-	-	33.6
Petro-Canada	8.6	51.4	1.2(1)	-	-	61.2
Shell	9.3	26.8	-	-	-	36.1(3)
NEB	6.2	37.9	0.4	(2)	-	44.5

Gross heating values applicable to NEB estimate:

B.C.	38.8 MJ/m^3
Alberta	38.8 MJ/m^3
Saskatchewan	36.8 MJ/m^3
S. Territories	36.8 MJ/m^3

(1) For all areas other than Alberta and British Columbia.
(2) Southern Territories included in British Columbia total.
(3) New discoveries only. Appreciation of current established reserves base not included.

Table 3-3

NEB FORECAST OF MARKETABLE

NATURAL GAS RESERVES ADDITIONS

CONVENTIONAL AREAS

1982-2000

(Exajoules)

Year	British Columbia	Alberta	Saskatchewan	Canada Total
1982	0.33	3.07	0.02	3.42
1983	0.34	2.86	0.02	3.22
1984	0.37	2.94	0.02	3.33
1985	0.47	3.21	0.02	3.70
1986	0.44	2.95	0.02	3.41
1987	0.42	2.70	0.02	3.14
1988	0.40	2.47	0.02	2.89
1989	0.38	2.26	0.02	2.66
1990	0.36	2.07	0.02	2.45
1991	0.34	1.90	0.02	2.26
1992	0.32	1.74	0.02	2.08
1993	0.30	1.59	0.02	1.91
1994	0.29	1.45	0.02	1.76
1995	0.27	1.35	0.02	1.64
1996	0.26	1.25	0.02	1.53
1997	0.24	1.15	0.02	1.41
1998	0.23	1.07	0.02	1.32
1999	0.22	0.98	0.02	1.22
2000	0.21	0.90	0.02	1.13
TOTAL	6.19	37.91	0.38	44.48

were provided by eight submittors, with two from Consolidated. These estimates are listed by region in Table 3-4. Four submittors increased estimates of ultimate potential since the June 1981 Report, while the remaining four submittors did not re-evaluate previously submitted estimates.

Many submittors included some component of unconventional reserves in their estimates of ultimate potential.

After reviewing the evidence, and taking into account the most recent trends in reserves additions, the Board felt justified in increasing its estimate of ultimate potential of natural gas in conventional areas to 183 EJ. This is an increase of 13 EJ over the base case estimate of 170 EJ used in the June 1981 Report. Increases of 9 EJ are estimated for Alberta and 4 EJ for British Columbia.

3.1.3 Natural Gas Deliverability

Thirteen forecasts of natural gas deliverability from established reserves in conventional areas were submitted. Submittors used a variety of forecast approaches, including some based on GEMM, a commercially available computer model. The Board employed its computerized gas deliverability model, which it developed, and has had under improvement for several years. As Figure 3-1 shows, the Board's forecast falls within the range of submittors' forecasts. Some 16 forecasts of total gas supply from conventional areas including deliverability from future reserves additions were provided. The range of these forecasts and the Board's forecast are shown in Figure 3-2.

The Board's forecast of supply from reserves under the control of major gas purchasers is presented in Table 3-5. The forecast is based on a pool-by-pool analysis of gas deliverability reflecting well flow characteristics, basic reservoir parameters, and daily contract rates. All forecasts in Table 3-5 were prepared with the Board's computer model except those for Many Islands, Ocelot and production east of Alberta. Many Islands and Saskatchewan production were adopted from forecasts submitted by Saskatchewan Power Corporation. The Board's production forecast for Ocelot was prepared using the Board's shallow gas deliverability profile. Production for Ontario was estimated by the Board based on production history.

All non-contracted reserves in British Columbia and the Southern Territories were considered to be controlled by Westcoast.

Alberta reserves as of 31 December 1981, which were not included in the controlled reserves forecasts, were classified into three categories: uncommitted, deferred, and beyond economic reach.

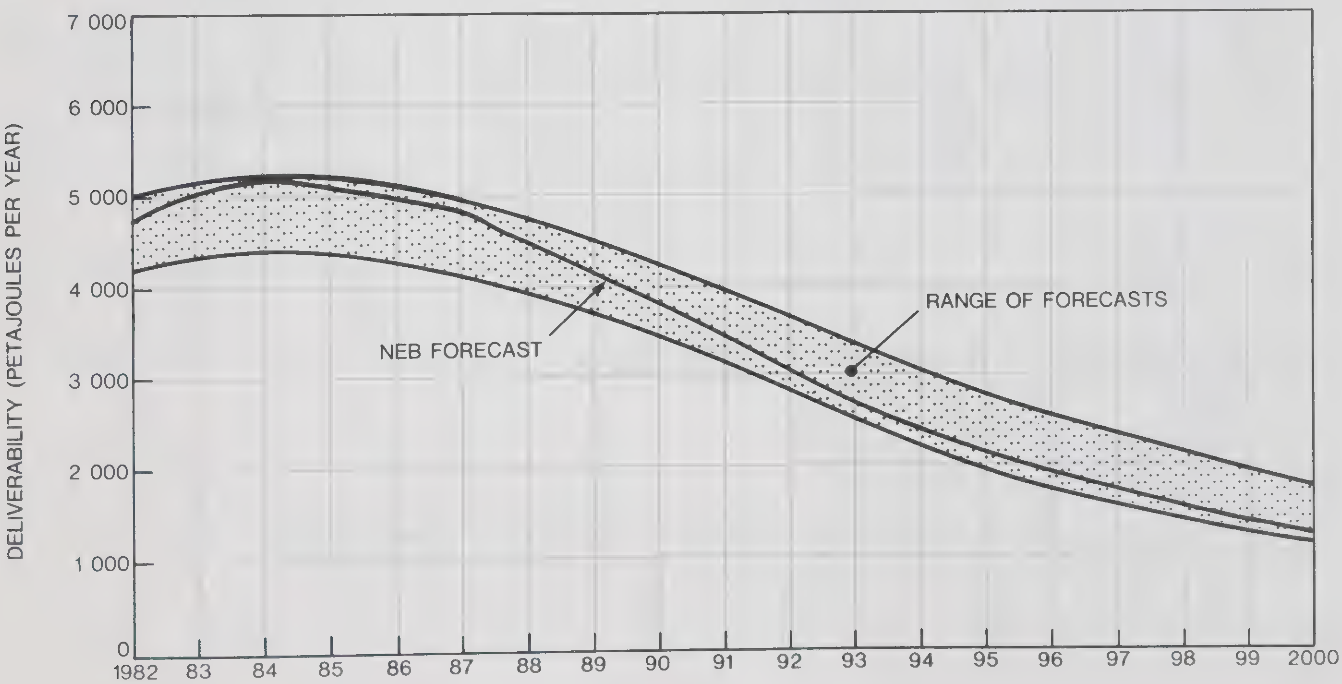

Figure 3-1 Natural Gas Deliverability From Conventional Areas
Established Reserves Only
Comparison of Forecasts

Table 3-4

ULTIMATE POTENTIAL ESTIMATES OF MARKETABLE NATURAL GAS

CONVENTIONAL AREAS

COMPARISON OF ESTIMATES

(Exajoules)

	B.C.	Alta.	Sask.	Southern Territories	Eastern Canada	Canada Total
Consolidated						
Current	34	147	7(1)	-	-	188
Improved	41	217	7(1)	-	-	265
CPA	41	165	4	2	1	213
Dome	36	174	7	4	1	222
Esso	29	168	3	2	1	203
Gulf	27	171	3	5	2	208
IPAC	-	-	-	-	-	190+
Petro-Canada	49	170	3	2	1	225
Shell	40	157	3	-	1	200
NEB 1981						
Base	21	145	3	-(2)	1	170
Low	19	135	3	-(2)	1	158
High	26	165	3	-(2)	1	195
NEB 1982						
Base	25	154	3	-(2)	1	183

Gross heating values applicable to NEB estimate:

B.C.	38.8 MJ/m^3
Alberta	38.8 MJ/m^3
Saskatchewan	36.8 MJ/m^3
S. Territories	36.8 MJ/m^3

(1) Southern Territories and Eastern Canada included in Saskatchewan.

(2) Southern Territories included in British Columbia total.

Table 3-5

NEB Forecast of Natural Gas Deliverability from Controlled Reserves

(Petajoules/Year)

Year	Trans-Canada	A&S	WTCL GL-41	WTCL GL 4	Pan-Alberta PA 80-3	Pan-Alberta PA 81-4	ProGas 1	ProGas 2	Sulpetro	Canadian-Montana	Columbia	KannGaz	Ocelot	Many Islands Pipelines	Alberta Utili-ties	Production East of Alberta	Total
1981*	24 602	6 745	9 932	149	978	5 210	1 834	1 618	233	191	169	669	442	637	6 644	1 565	61 618
1982	2 249	619	519	35	87	400	115	0	0	16	16	0	0	39	430	55	4 580
1983	2 253	610	531	29	102	546	119	0	28	13	16	10	0	36	423	57	4 774
1984	2 212	585	534	24	95	492	117	142	26	12	16	59	0	35	388	63	4 799
1985	2 127	545	512	13	90	445	115	139	22	10	16	59	0	32	362	65	4 551
1986	2 000	497	501	4	84	393	113	130	19	11	16	59	46	30	348	63	4 312
1987	1 856	499	501	4	78	347	110	121	16	10	16	59	45	28	333	62	4 082
1988	1 648	465	481	4	69	295	107	114	14	9	16	59	44	26	315	58	3 722
1989	1 389	424	455	4	59	252	102	104	11	8	16	57	43	24	287	55	3 288
1990	1 223	381	413	4	54	229	96	96	10	7	16	52	42	22	275	52	2 971
1991	1 031	336	372	4	46	203	94	88	9	7	16	46	39	20	260	49	2 617
1992	865	293	342	4	37	179	89	79	8	6	11	33	34	19	241	45	2 284
1993	730	256	318	4	32	161	75	72	8	5	0	19	22	17	221	41	1 981
1994	613	213	298	4	24	144	62	62	7	5	0	14	22	16	204	38	1 726
1995	525	182	281	4	18	127	55	52	6	5	0	11	18	15	190	35	1 523
1996	450	160	249	4	16	111	48	44	6	4	0	10	16	14	175	32	1 336
1997	367	132	231	4	13	97	41	38	3	4	0	8	13	13	159	30	1 152
1998	312	108	210	3	11	87	35	29	3	4	0	7	11	12	147	28	1 006
1999	272	89	190	1	9	77	24	22	3	3	0	6	9	11	133	25	876
2000	227	74	173	0	8	69	22	19	3	3	0	6	8	10	119	24	764
Total	22 350	6 467	7 110	149	931	4 653	1 540	1 350	199	140	169	571	411	420	5 010	875	52 346

Note: Figures may not add due to rounding.

* Remaining Reserves at year end.

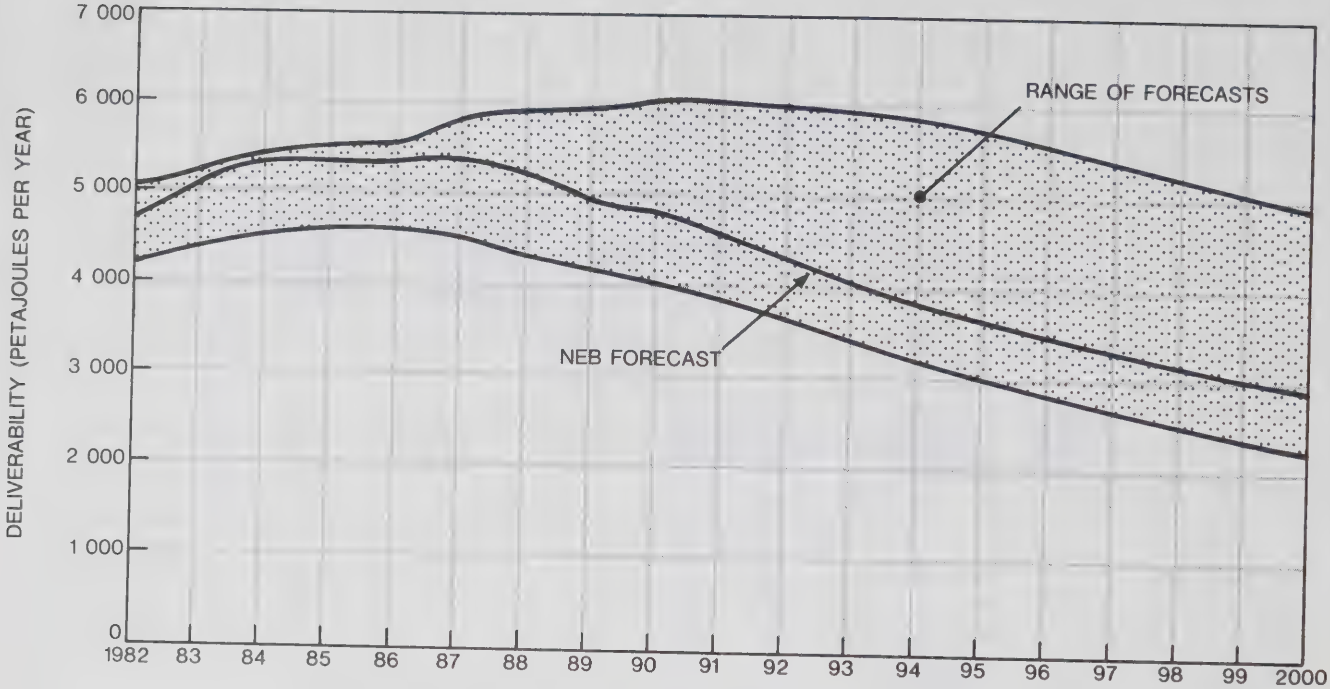

Figure 3-2 Natural Gas Deliverability From Conventional Areas
Established Reserves and Reserves Additions
Comparison of Forecasts

The Board estimates that as of 31 December 1981 there were some 13.6 EJ of uncommitted gas reserves in Alberta including some 3.2 EJ of Southeastern Alberta shallow gas reserves. All uncommitted gas reserves were connected using the Board's connection schedule presented in its November 1979 Reasons for Decision (i.e., percent connection by year of 15, 15, 15, 15, 15, 10, 5, 3, 3, 2, 1, 1).

The deliverability profile for the 3.2 EJ of uncommitted shallow gas reserves was derived from the profile generated by the deliverability model for all committed shallow gas. The deliverability profile for other uncommitted reserves and for future reserves additions was the same as in the June 1981 Report. The profile is based on an initial rate of 1:7000 and a flat life of eight years with production declining thereafter at 8.22 percent per year.

The Board finds that as of 31 December 1981, there were some 4.3 EJ of deferred gas reserves in Alberta. TransCanada's forecast of deliverability from these deferred reserves presented at the 1980-81 Energy Inquiry is considered to be reasonable and has been adopted. TransCanada's forecast of deferred reserves excludes some 0.4 EJ of deferred reserves under contract to TransCanada. The Board has included TransCanada's deferred reserves in its forecast of TransCanada's system supply.

Future reserves additions were connected at the same rate as in the Board's November 1979 Reasons for Decisions (i.e., percent connection by year of 10, 15, 20, 25, 15, 5, 2, 2, 1, 1, 1, 1, 1, 1) and those in Alberta and British Columbia were produced using the deliverability profile described earlier. Since Saskatchewan reserves additions are expected to be to a considerable extent shallow gas reserves similar to those in Southeastern Alberta, the shallow gas deliverability profile referred to earlier was employed for these additions.

The Board's forecasts of deliverability from established reserves and future reserves additions are detailed in Table 3-6.

3.2 Demand

The Board's assessment of total energy requirements in the various sectors and regions is based on assumptions regarding the growth path of selected economic and demographic variables, on future energy prices and government policies, and on the evidence presented by submittors. The demand for the different forms of energy is then determined by estimating future market shares.

Considerable evidence on natural gas demand was presented at the Hearing. Forecasts of submittors are summarized and compared with the projections of the Board in Table 3-9.

Table 3-6

NEB FORECAST OF NATURAL GAS DELIVERABILITY FROM CONVENTIONAL AREAS

(Petajoules/Year)

Year	DELIVERABILITY FROM ESTABLISHED RESERVES						SUPPLY FROM RESERVES ADDITIONS				
	Total Controlled	S.E. Alberta Uncom-mitted	Other Alberta Uncom-mitted	Alberta BER	Alberta Deferred	Total	Alberta	British Columbia	Saskatch-ewan	Total	TOTAL CANADA SUPPLY CAPABILITY
1981*	61 618	3 190	10 410	1 522	3 974	80 714	37 910	6190	380	44480	
1982	4 580	49	82	2	3	4 716	16	2	0	18	4 734
1983	4 774	98	163	3	3	5 040	55	6	1	62	5 102
1984	4 799	146	245	5	4	5 198	125	14	2	140	5 338
1985	4 551	193	326	6	6	5 082	234	27	3	265	5 347
1986	4 312	238	407	8	6	4 971	367	44	5	416	5 387
1987	4 082	264	462	10	6	4 823	506	63	7	576	5 399
1988	3 722	268	489	11	12	4 502	647	83	8	738	5 240
1989	3 288	253	505	13	27	4 085	784	104	10	897	4 983
1990	2 971	238	515	14	42	3 781	911	124	11	1 046	4 827
1991	2 617	218	513	16	39	3 402	1 027	143	13	1 182	4 584
1992	2 284	192	500	17	35	3 027	1 129	160	14	1 303	4 331
1993	1 981	168	482	18	32	2 680	1 216	176	15	1 407	4 088
1994	1 726	145	453	19	28	2 371	1 287	190	16	1 493	3 864
1995	1 523	125	423	20	46	2 136	1 343	202	16	1 562	3 698
1996	1 336	106	392	21	45	1 900	1 383	212	17	1 612	3 512
1997	1 152	89	363	22	100	1 727	1 409	220	18	1 646	3 373
1998	1 006	75	335	22	97	1 535	1 422	227	18	1 667	3 202
1999	876	62	309	23	95	1 364	1 425	231	18	1 675	3 039
2000	764	50	284	24	112	1 233	1 419	234	19	1 672	2 905
Total	52 346	2 976	7 245	271	738	63 576	16 705	2 464	208	19 377	82 953

Note: Figures may not add due to rounding.

*Remaining Reserves at year end.

The Board has developed two demand scenarios, a Base Case and an Alternative Case scenario, based on different oil price assumptions, but on the same macroeconomic projection. From the two projections, the Base Case scenario, which projects a somewhat higher demand for total energy and for natural gas than does the Alternative Case, is used for the calculation of natural gas surplus. Two sensitivity cases have also been briefly examined to assess the impact of higher and lower price assumptions and higher economic growth on the demand for energy.

The Board's macroeconomic projection assumes that real GNP growth would average about 2.2 percent per year between 1982 and 1987. Over the longer term, real growth is projected at an average annual rate of about three percent. The projected growth profile implies a very gradual decline in the margin of slack in the economy over the next five years. Over the longer term the growth projection assumes some rebound in productivity growth from the recent low rate, but rates of productivity growth remain significantly below those achieved in the 1960's and early 1970's.

In the Base Case demand scenario, the real price of imported oil is assumed to decline by 20 percent over the period 1982 to 1985 and remain constant thereafter. In the Alternative Case the real price of imported oil is assumed to remain constant at the 1981 level. Both assumptions reflect the view that recent softness of the world oil market and the large shut-in oil production capacity of OPEC is likely to militate against real price increases, at least in the 1980's. These price scenarios are illustrated in Figure 3-3.

The Board assumes that the pricing policies established in the NEP, the NEP-Update, and in the agreements between the Federal Government and the producing provinces will continue throughout the projection period. The following table summarizes the resulting increase in the real price of domestic oil for both demand scenarios:

Table 3-7

AVERAGE ANNUAL INCREASE IN THE REAL PRICE OF DOMESTIC CRUDE OIL AT TORONTO

(percent)

	1981-85	1985-90	1990-2000
Base Demand Case	3.2	2.7	0.5
Alternative Demand Case	7.8	3.2	0.7

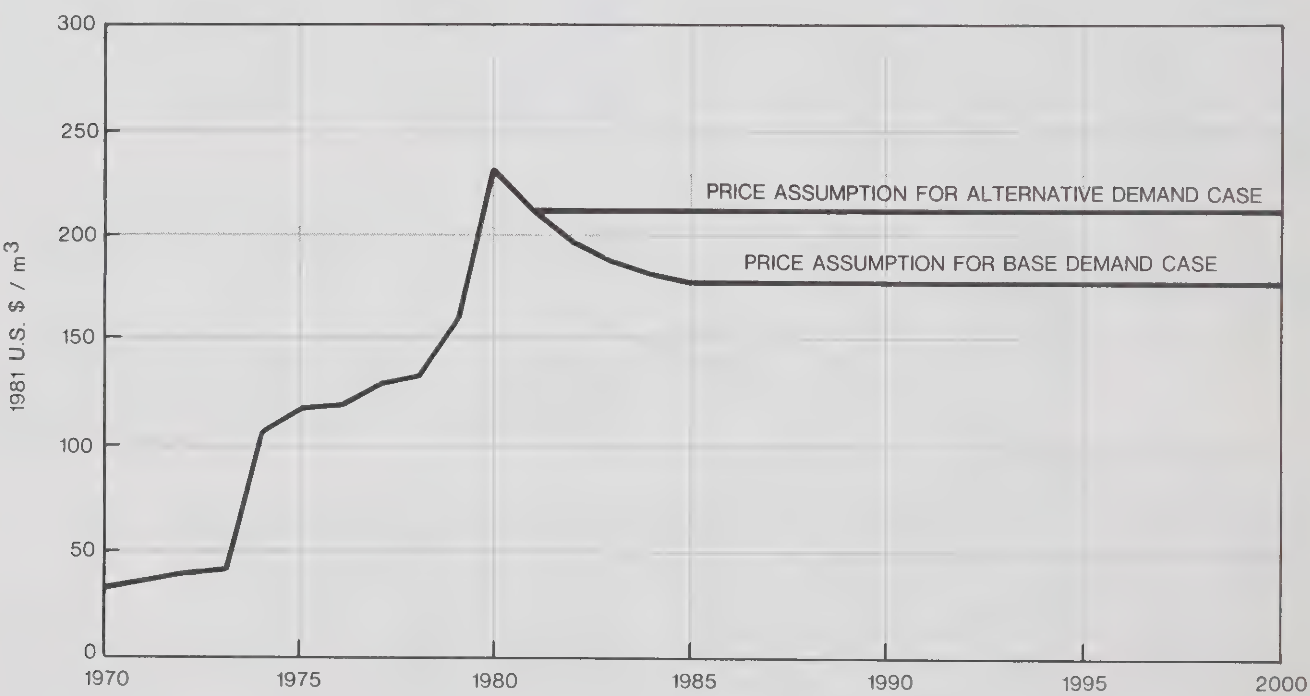

Figure 3-3 Real Price of Imported Oil

(Average import price at port of loading. U.S. Wholesale Price Index (1981 = 100) was used to calculate 1981 U.S. dollar prices.)

Reflecting the provisions of federal/provincial agreements, the Toronto city-gate price of natural gas is assumed to be maintained throughout the forecast period at approximately 70 percent of the price of crude oil at the Toronto refinery-gate for the Base Demand Case, and approximately 65 percent for the Alternative Demand Case. Many of the submittors to the hearing assumed, however, that the price of natural gas would gradually increase after 1986 to somewhere between 75 and 85 percent of the price of oil. Electricity prices to 1986 for each province are based on utility announcements and on estimates by the Board. After 1986, electricity prices in each province are assumed to remain constant in real terms.

These price assumptions imply a continuation of the price advantage of natural gas over both electricity and oil; electricity becomes increasingly more competitive with oil, especially in the residential and commercial sectors.

In its energy demand projections the Board has assumed that the existing array of federal and provincial policies implementing the off-oil strategy remain in place. It also has assumed that gas will be made available to Eastern Quebec between 1982 and 1985, to Vancouver Island in 1985, and to the Maritimes in 1987 - coinciding with the estimated availability of supply from Sable Island.

In the Base Case, the Board projects total primary energy demand in Canada to increase from 10 270 PJ in 1980 to 11 946 PJ by 1990 and to 15 115 PJ by the year 2000, representing average annual growth rates of 1.5 percent and 2.4 percent, respectively, in the two decades. In the Alternative Case, total primary energy demand increases at a somewhat slower rate to 11 589 PJ by 1990 and to 14 502 PJ by the year 2000, at average growth rates of 1.2 percent and 2.3 percent, respectively.

The slower growth in demand during the 1980's than in the 1990's reflects the assumptions that:

(i) the bulk of the increases in real domestic energy prices will occur in the 1980's and that their impact on demand will gradually wear off during the 1990's; and

(ii) economic growth will be slower in the remaining years of the 1980's than in the 1990's.

The present projection of primary energy demand is approximately seven percent lower in 1990 and nine percent lower in the year 2000 than in the Middle Demand Case shown in the Board's June 1981 Report on Canadian Energy Supply and Demand: 1980-2000. It is generally in agreement with the evidence presented at this Hearing and reflects a lower projection of economic activity as well as different assumptions regarding prices than were used in the June 1981 Report.

The projections of energy demand imply that the overall intensity of energy use, measured by the combined secondary energy consumption in the residential, commercial, industrial, and transportation sectors per unit of real GNP will decline by some 18 percent between 1981 and 2000 in the Base Case and by 22 percent in the Alternative Case.

The share of crude oil in total primary energy demand is projected to decline from approximately 40 percent in 1980 to 25 percent by the year 2000.

The projected share of natural gas in the demand for total secondary energy in the three major gas consuming sectors is shown for the Base Case in Table 3-8.

Table 3-8

SHARE OF NATURAL GAS IN TOTAL

SECONDARY ENERGY BY SECTOR - BASE CASE

(percent)

	1980	1985	1990	2000
Residential Sector	33.1	40.5	44.7	45.6
Commercial Sector	40.6	47.3	51.0	53.5
Industrial Sector	26.4	28.1	32.0	38.4

In its present projections, the Board anticipates a rapid increase in the market share of natural gas in the 1980's in each of the residential, commercial and industrial sectors, caused mainly by the substitution of gas for oil induced by lower gas prices relative to most of the other fuels, expansion of gas markets, and other government programs encouraging oil substitution.

For the first time the Board has made allowance for the use of CNG as transportation fuel in its projections. CNG use is assumed to increase from negligible levels in 1981 to 41 PJ per year in 2000, representing use by about 715 000 vehicles.

Table 3-9

NATURAL GAS DEMAND - CANADA

COMPARISON OF PROJECTIONS

(Petajoules)

Submittors(1)	1980	1981	1982	1983	1985	1990	1995	2000
CPA(2)	N/A	N/A	1 821	1 902	2 093	2 446	2 745	2 989
Dome	N/A	N/A	1 864	1 977	2 144	2 466	2 711	2 951
Esso	1 780	1 690	1 845	N/A	2 010	2 275	N/A	2 560
Gulf	1 787	1 708	1 776	N/A	N/A	2 297	N/A	2 773
Norcen	1 754	1 791	1 803	1 916	2 072	2 402	2 633	2 876
NOVA	N/A	N/A	1 833	1 900	2 184	2 552	2 721	2 916
Pan-Alberta	1 781	N/A	N/A	N/A	2 203	2 415	2 659	3 044
Petro-Canada(3)	1 752	1 744	1 871	1 969	2 184	2 566	2 885	3 192
Shell	1 758	1 706	1 752	1 832	2 014	2 423	2 764	3 072
TransCanada(4)	N/A	N/A	N/A	2 051	2 316	2 754	2 935	3 223
High(5)	1 787	1 791	1 871	2 051	2 316	2 754	2 935	3 223
Median	1 769	1 708	1 827	1 916	2 138	2 434	2 733	2 970
Low(5)	1 752	1 690	1 752	1 832	2 010	2 275	2 633	2 560
1981 NEB Projections(6)								
High	1 781	N/A	N/A	N/A	2 630	3 212	3 782	4 566
Middle	1 781	1 873	1 958	2 103	2 323	2 664	2 955	3 410
Low	1 781	N/A	N/A	N/A	2 228	2 436	2 666	3 053
1982 NEB Projections(7)								
Base Case	1 770	1 721	1 716	1 778	2 030	2 441	2 886	3 280
Alternative Case	1 770	1 721	1 716	1 776	1 992	2 363	2 779	3 154

(1) Consolidated, IPAC, and ProGas projections were excluded because they included part, or all of reprocessing fuel and shrinkage demand in their estimates.
(2) CPA's forecast has also been adopted by A&S.
(3) Forecast probably excludes reprocessing fuel and shrinkage.
(4) Year commences November 1st previous to the year indicated.
(5) High and low values shown do not necessarily represent the same submittor for each year shown.
(6) These three projections were prepared in the course of the 1981 Supply and Demand Hearing. The middle case was shown in the June 1981 Report (Table 7-1, page 69).
(7) 1980 and 1981 are actuals.

The Board's projection of total natural gas demand is compared with those of the submittors in Table 3-9 and Figure 3-4, and projected net sales of natural gas by region are shown in Table 3-10. The comparison of projections indicates that up to 1990 both of the Board's demand scenarios are on the low side of the range of submittors' projections. After 1990, however, the Board's projections show a higher rate of growth in demand than those projected by the submittors and, as a result, by the year 2000 the Base Case is some 1.8 percent above the highest projection submitted to the hearing. The Board's relatively high projection of natural gas demand in the 1990's reflects:

(i) the assumption that most of the increases in the real price of energy in Canada will take place in the 1980's and that their impact on demand will have largely worn off by the 1990's;

(ii) the Board's relatively lower gas price projections, especially for the 1990's, which result from a combination of generally lower oil price projections and lower assumed gas/oil price ratios; and

(iii) the Board's assumption that, on average, real economic growth in the 1990's will be slightly greater than in the 1980's.

3.3 Allowance for Existing Exports

Reserves Formula

As indicated in Chapter 1, the Board's Phase I Decision of May 1982 included a change to the Reserves Formula to base the allowance for exports under existing licences on maximum quantities exportable under existing licence conditions rather than the remaining term quantities in the licences.

In this regard, the Board has prepared Table 3-11, which details the maximum quantities exportable under existing licence conditions. The Board made the following assumptions in the preparation of the allowance for exports:

a) for licences containing annual averaging, the maximum daily licensed quantity (adjusted for heat content) times the days in the year was used;

b) for licences without annual averaging, the maximum annual licensed quantity (adjusted for heat content) was used;

c) for both a) and b) above, the duration of the allowance was limited to either the remaining term quantity in the licence or until the expiry of the term of the licence.

A result of adopting these procedures in the Reserves Formula is that quantities included in the term volume of a licence that cannot be exported (so-called "trapped gas") are now part of the available surplus.

In summary, the allowance for existing exports for use in the Reserves Formula is 12.5 EJ which includes 0.5 EJ for fuel required in Canada to transport these quantities.

Deliverability Appraisal

The Board's Phase I Decision also dealt with the manner in which deliverability would be assessed in determining the time pattern of volumes available for export. With respect to the allowance made for exports under existing licences, the Board decided to incorporate a forecast of exports under existing licences rather than base the allowance on the maximum quantities exportable under the current licence conditions.

The Board's allowance for existing exports for use in the Deliverability Appraisal is shown in Table 3-12. The forecast was prepared on the basis of Applicants' forecasts which were requested by the Board. A review of each licence-holder's estimate revealed that companies generally expected export sales to remain at fairly low levels for 1982, the first year of the forecast period, but that starting in 1983 and 1984 exports would increase from 50 percent of authorized volumes in 1982 to 85 percent in 1984.

The Board believes that exports will not recover as soon as 1983-84. In light of the current short-term market and supply outlook in the United States, the Board has forecast exports for 1983 and 1984 at 63 and 71 percent of authorized levels compared to composite levels of 70 and 85 percent submitted by exporters. The Board in its forecast shows exports increasing to some 78 percent in 1985 and 84 percent by 1986.

For the subsequent years the Board adopted the companies' estimates with two exceptions. The

Table 3-10

NEB BASE CASE PROJECTIONS OF NATURAL GAS NET SALES

(Petajoules)

	1980(1)	1981(1)	1982	1983	1985	1990	1995	2000
Maritimes	N/A	N/A	N/A	N/A	N/A	31	60	85
Quebec	109	119	120	129	174	257	308	350
Ontario	698	695	695	705	755	884	1 027	1 139
Manitoba	71	63	65	67	69	77	87	96
Saskatchewan	102	98	96	96	104	122	143	168
Alberta	506	478	462	489	591	689	798	926
British Columbia	166	152	160	166	193	245	309	344
TOTAL	1 651	1 604	1 598	1 651	1 886	2 305	2 732	3 108

(1) 1980 and 1981 are actuals.

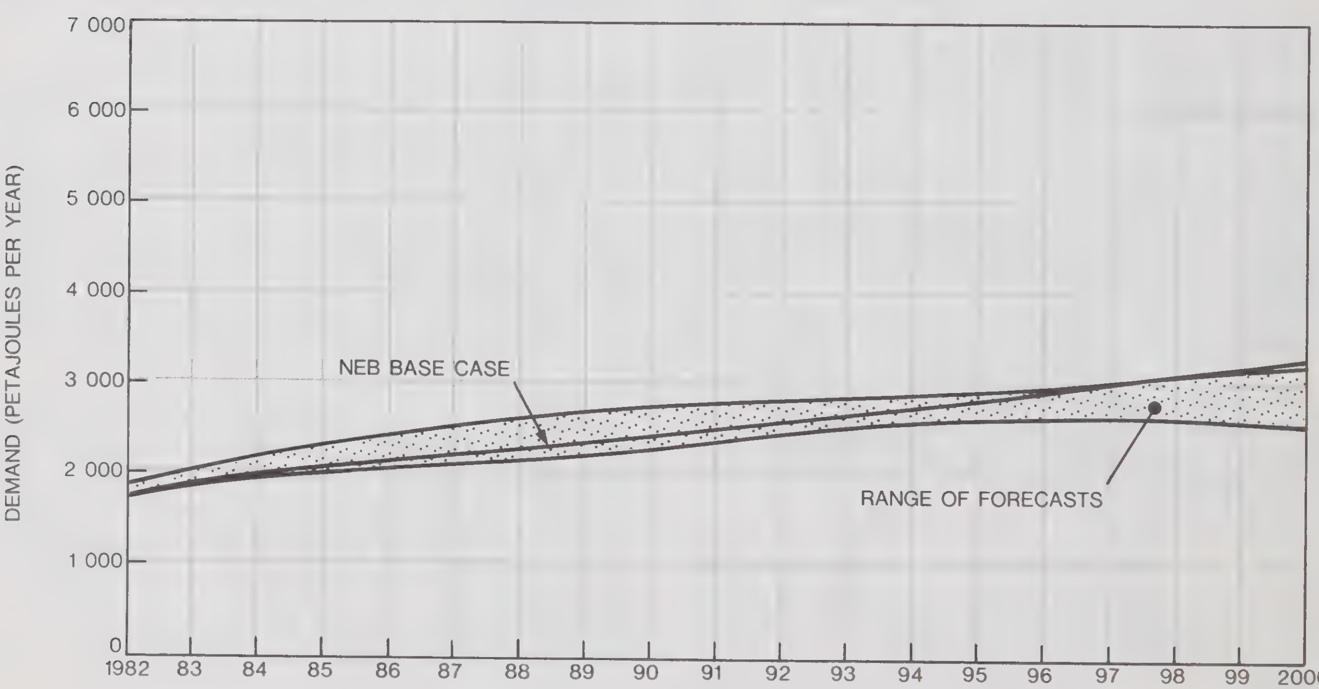

Figure 3-4 Natural Gas Demand - Canada Comparison of Forecasts

Table 3-11

Maximum Quantities Exportable Under

Existing Licence Conditions

(Petajoules)

Exporter	Licence Number	Delivery Point	Term Quantity Remaining as at 12/31/81	1982	1983	1984	1985	1986	1987	1988	1989	1990	1991	1992	1993
A&S	GL-3	Kingsgate	900.6	181.8	181.8	182.3	181.8	159.0	13.9						
	GL-16	"	631.6	89.7	89.7	89.9	89.7	89.7	89.7	89.9	3.4				
	GL-24	"	1 005.4	93.5	93.5	93.8	93.5	93.5	93.5	93.8	93.5	93.5	86.9	53.8	22.4
	GL-35	"	385.4	81.2	81.2	81.5	74.5	37.2	16.9						
Pan-Alberta	GL-59	"	513.8	95.4	95.4	91.4	67.6	43.7	35.2	76.9					
	GL-63	"	238.4	13.0	14.8	27.8	58.2	111.8	12.7						
Westcoast	GL-4	"	379.8	50.8	55.4	53.1	39.2	25.4	11.5						
Cdn-Montana	GL-5	Niagara Falls	62.3	14.0	14.0	14.0	14.0	6.2							
	GL-17	"	63.9	9.3	9.3	9.4	9.3	9.3	9.3	7.8					
	GL-25	"	51.8	9.3	9.3	9.4	9.3	9.3	5.1						
	GL-53	"	3.2					1.6	1.6						
Sulpetro	GL-57	"	38.3	27.8	10.6										
Consolidated	GL-61	Emerson	127.2	33.4	33.4	30.2	11.6								
ProGas	GL-56	"	221.9	75.6	50.0	45.2	17.4								
TCPL	GL-18	"	565.4	58.8	58.8	58.9	58.8	58.8	58.8	58.9	48.9				
	GL-18	Niagara	52.7*	52.7											
	GL-20	Emerson	379.5	36.6	36.6	36.7	36.6	36.6	36.6	36.7	36.6	36.6	30.5		
	GL-37	"	695.9	76.2	76.2	76.4	76.2	76.2	76.2	76.4	76.2	63.5			
	GL-38	"	184.0	19.5	19.5	19.5	19.5	19.5	19.5	19.5	19.5	16.3			
	GL-39	"	26.4	2.8	2.8	2.8	2.8	2.8	2.8	2.8	2.8	2.3			
	GL-60	"	320.7	78.9	78.9	75.6	49.9								
Columbia	GL-54	Monchy	90.1	0.7	3.9	3.9	3.9	3.9	3.2						
Consolidated	GL-61	"	270.3	44.4	44.4	44.4	43.5	35.7	16.2						
Pan-Alberta	GL-58	"	1 404.5	312.1	312.1	299.1	221.1	171.4	88.7						
	GL-62	"	297.8			13.0	91.0	140.7	53.1						
ProGas	GL-56	"	394.5	41.0	66.6	66.6	65.2	53.5	24.3						
Westcoast	GL-41	"	137.2	17.5	17.5	17.6	17.5	17.5	17.5	17.6	14.6				
ICG	GL-28	Sprague	5.3	1.1	1.1	1.1	1.1	0.8							
	GL-29	Fort Frances	125.7	12.6	12.6	12.6	12.6	12.6	12.6	12.6	12.6	12.6	12.4		
Niagara Gas	GL-6	Cornwall	32.1	6.9	6.9	6.9	6.9	4.4							
	GL-55	"	23.1	3.4	3.4	3.2	3.0	4.7	2.1						
TCPL	GL-19	Phillipsburg	59.3	8.2	8.2	8.3	8.2	8.2	8.2	8.3	1.5				
Westcoast	GL-41	Huntingdon	3 000.3	351.4	351.4	352.4	351.4	351.4	351.4	352.4	292.7				
Cdn-Montana	GL-52	Aden	60.2	10.9	10.9	10.9	8.2	5.4	2.7						
	GL-36	Cardston	22.1	4.8	4.8	4.8	4.4	2.2	1.2						
Totals (may not add due to rounding)			12 770.7	1 915.3	1 855.1	1 842.6	1 747.9	1 593.1	1 064.8	853.5	602.3	224.8	129.8	53.8	22.4

*includes quantities authorized as interruptible volumes under GL-18, GL-20, GL-37

first was for Pan-Alberta, which had forecast exports increasing from 70 percent in 1983 to 80 percent in 1984, 85 percent in 1985, 90 percent in 1986 and 95 percent in 1987 and 1988. The Board's forecast limits the increase to 75 percent in 1984, rising to 80 percent in 1985, and then remaining at 85 percent to the end of the licence term. In the Board's view 85 percent, which is the minimum take-or-pay level in the contract, would probably be the maximum quantity that would be sold by Pan-Alberta during this period.

The Board also reduced the forecast of exports submitted by Westcoast. In the Board's view Westcoast's estimate of sales at 80 percent of authorized quantities for the period 1984 through 1989 cannot be substantiated, given the evidence of various participants during the proceedings. Based on this testimony the Board has developed its own forecast for Licence GL-41 that includes an estimate of sales for the Pacific Northwest market area, the offline sale to Texas Eastern/Transwestern, and the sale at Monchy, Saskatchewan to Texas Gas.

The Board has included its own forecast for ICG for exports at Sprague, Manitoba and Fort Frances, Ontario, since ICG was not an applicant in this hearing.

In summary, Table 3-12 shows that for the period of the forecast approximately 75 percent of the total quantity authorized would be exported. In 1982, exports would be near 50 percent of that authorized; this would rise to 78 percent by 1985 and to nearly 100 percent by 1990.

3.4 Surplus Determination

3.4.1 Introduction

In this section, Board judgements on reserves, deliverability, demand and the allowance for exports under existing licences are brought together in the determination of quantities surplus to reasonably foreseeable Canadian requirements.

The Board, since 1960, has employed a calculation similar to the Reserves Formula to determine the quantities of gas which are surplus to domestic requirements. This calculation shows the remaining quantity of established gas reserves, from which domestic requirements (represented as 25 times present requirements - 25A1) and existing export approvals are subtracted to identify those quantities which are surplus to Canadian needs.

In its Phase I Report the Board outlined, in detail, changes that would be made to procedures for appraising deliverability in the issuance of new licences. Briefly, the Board has decided to use the Deliverability Appraisal as a guideline to determine annual quantities of exports rather than as a rigid calculation in the determination of surplus. The supply and demand information used in the Deliverability Appraisal includes the following:

- deliverability from established reserves,
- deliverability from established reserves and from future reserves additions,
- expected Canadian requirements, and
- estimated exports under existing licences.

3.4.2 Surplus Calculations

The Reserves Formula

Table 3-13 shows the calculation of surplus in accordance with the Reserves Formula. The calculation has been made as of 31 December 1981, which is the latest date for which data for remaining established reserves were available. In this calculation the Board used estimated domestic gas requirements for the year 1982 (multiplied by 25) as the provision for Canadian sales.

The surplus of 18.4 EJ resulting from this calculation can be compared with 9.3 EJ that is shown for 31 December 1980 on page 216 of the Board's June 1981 Report. The major differences between the two calculations are a net increase in established reserves of 4.6 EJ for year-end 1981 over year-end 1980; a lower estimate of Canadian sales in the first year of the forecast period resulting in a reduction of 3.5 EJ; and a reduction of 1.9 EJ in the allowance for export sales due to the change of procedures in the Reserves Formula and to take account of exports that took place in 1981.

The Deliverability Appraisal

The components of the Deliverability Appraisal are shown in Table 3-14. The estimation of the deliverability profile for established reserves and for reserves additions is explained in Section 3.1. The estimation of domestic demand and exports under existing licences is explained in Sections 3.2 and 3.3.

In applying the Deliverability Appraisal in this instance, the Board is guided by its Phase I Decision not to include deliverability from frontier reserves. Since the Board considers that demand in the Atlantic region will most likely be supplied

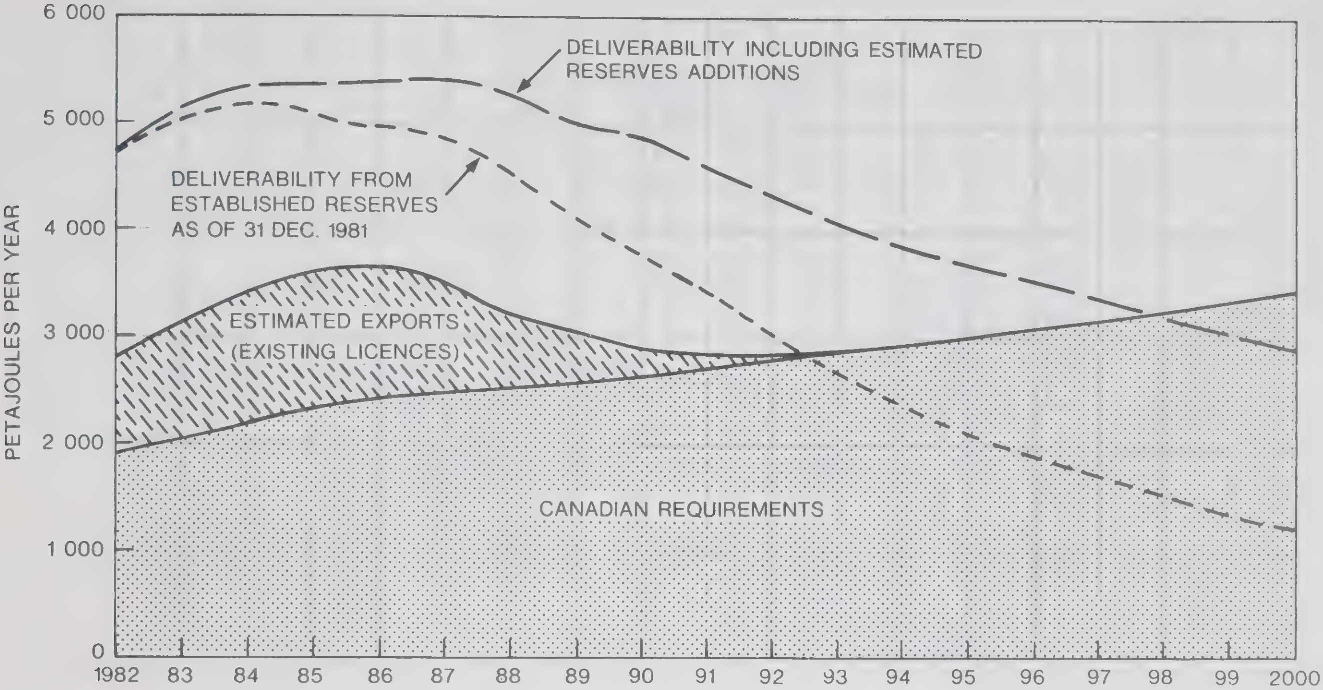

Figure 3-5 Deliverability Appraisal

from Sable Island, a supply source not included in the deliverability estimates shown, the assumption has been made that supply from Western Canada need not be set aside to meet future requirements in the Maritimes.

Figure 3-5 shows the Deliverability Appraisal graphically. Deliverability from established reserves is calculated using 31 December 1981 established reserves estimates; deliverability from reserves additions is generated from estimated reserves additions for 1982 and future years.

Table 3-12

ALLOWANCE[1] GIVEN FOR NATURAL GAS EXPORT LICENCES

(Petajoules)[2]

Company	Licence	Delivery Point	1982	1983	1984	1985	1986	1987	1988	1989	1990	1991	1992	1993	1994	1995	Total
A&S	GL-3	Kingsgate	119.8	124.8	124.8	133.1	131.0	34.6									668.1
	GL-16	"	58.5	60.9	60.9	65.0	73.1	89.8	90.2	75.1[4]							573.5
	GL-24	"	60.9	63.4	63.4	67.7	76.1	93.4	93.9	93.9	93.9	85.6	48.4	40.3[4]			880.9
	GL-35	"	52.8	55.0	55.0	53.7	30.2	15.3									262.0
Pan-Alberta	GL-59	"	72.1	66.8	68.5	54.0	37.1	16.9									315.4
	GL-63	"		2.8	20.9	41.3	64.2	67.5[4]									196.7
Westcoast	GL-4	"	34.7	36.9	45.4	33.5	21.7	9.8									182.0
Total		Kingsgate	398.8	410.6	438.9	448.3	433.4	327.3	184.1	169.0	93.9	85.6	48.4	40.3			3 078.6
Cdn-Montana	GL-5	Niagara Falls	0.9	7.6	9.3	10.5	10.2	2.4[4]									40.9
	GL-17	"	0.6	6.2	8.3	8.2	7.8	7.8	9.5	9.8[4]							58.2
	GL-25	"	0.6	6.2	8.3	8.2	7.8	7.8	9.5	0.4[4]							48.8
	GL-53	"					1.3	1.9[4]									3.2
Sulpetro	GL-57	"	16.6	15.4[4]													32.0
Total		Niagara Falls	18.7	35.4	25.9	26.9	27.1	19.9	19.0	10.2							183.1
Consolidated	GL-61	Emerson	26.4	27.2	27.6	20.7	13.4[4]	5.8[4]									121.1
ProGas	GL-56	"	46.7	51.6	57.0	50.6	36.4[4]	16.5[4]									258.8
TransCanada	GL-18	"	14.8	34.8	41.8	47.4	54.0	54.0	54.0	46.0							346.8
	GL-20	"	31.3	29.7	27.4	30.8	34.2	34.2	34.2	34.2	34.2	28.5					318.7
	GL-37	"	65.4	66.9	61.1	68.7	76.4	76.4	76.4	76.4	63.6						631.3
	GL-38	"	9.6	9.6	12.8	16.6	19.4	19.4	19.4	19.4	16.2						142.4
	GL-39	"	0.7	1.8	2.1	2.4	2.7	2.7	2.7	2.8	2.3						20.2
	GL-60	"	59.5	59.5	56.7	46.3											222.0
Total		Emerson	254.4	281.1	286.5	283.5	236.5	209.0	186.7	178.8	116.3	28.5					2 061.3
Cdn-Montana	GL-36	Cardston	12.2[3]	1.9	1.4	2.1	0.8	0.7									19.1
	GL-52	Aden		6.1	6.6	5.9	4.2	2.3									25.1
Total		Montana	12.2	8.0	8.0	8.0	5.0	3.0									44.2
Columbia	GL-54	Monchy	0.5	4.9	11.9	8.8	6.9	3.5[4]									36.5
Consolidated	GL-61	"	26.4	27.2	27.6	20.7	13.4	5.8									121.1
Pan-Alberta	GL-58	"	37.6	218.5	224.3	176.9	145.7	193.3[4]	86.8[4]								1 083.1
	GL-62	"			9.7	72.8	119.6	45.1									247.2
ProGas	GL-56	"	18.1	24.2	26.8	23.7	16.6	7.5									116.9
Westcoast	GL-41	"	2.0	11.7	11.7	11.7	11.7	11.7	11.7	9.8							82.0
Total		Monchy	84.6	286.5	312.0	314.6	313.9	266.9	98.5	9.8							1 686.8
ICG	GL-28	Sprague	0.3	0.3	0.3	0.4	0.4	0.4[4]	0.4[4]	0.4[4]	0.4[4]	0.4[4]	0.4[4]	0.4[4]	0.4[4]	0.3[4]	5.2
	GL-29	Fort Frances	4.9	4.9	4.9	6.2	6.2	6.6	6.6	6.6	6.6	6.6	6.6[4]	6.6[4]	6.6[4]	5.5[4]	85.4
Total		ICG	5.2	5.2	5.2	6.6	6.6	7.0	7.0	7.0	7.0	7.0	7.0	7.0	7.0	5.8	90.6
Niagara Gas	GL-6	Cornwall	4.1	4.3	4.4	5.0	4.4	3.4[4]									25.6
	GL-55	"	2.0	2.1	2.1	1.8	3.3	2.2									13.5
Total		Cornwall	6.1	6.4	6.5	6.8	7.7	5.6									39.1
TransCanada	GL-19	Philipsburg	5.0	5.3	4.8	5.2	5.7	5.8	5.9	4.7[4]							42.4
Westcoast	GL-41	Huntingdon	102.1	104.0	179.3	190.4	190.4	190.4	190.4	158.5							1 305.5
Total		ALL LICENCES	887.1	1 142.5	1 267.1	1 290.3	1 226.3	1 034.9	691.6	538.0	217.2	121.1	55.4	47.3	7.0	5.8	8 531.6

1 Allowance excludes GL-43 fuel licence and Union Gas GL-64 licence for SNG export.

2 GHV (MJ/m^3) - Huntingdon @ 39.10, Kingsgate @ 38.33, Cardston @ 38.33, Aden @ 36.06. All points east of Alberta @ 37.63.

3 1982 estimate includes allowance for GL-5, GL-17, and GL-25.

4 Includes recovery of undelivered quantities in earlier years.

Table 3-13

RESERVES FORMULA

(Exajoules)

	As of 31 Dec. 1981	
Remaining Established Reserves	80.8	
Less Deferred Reserves (1)	1.3	
Less One-half of Reserves Beyond Economic Reach (2)	0.8	
Less Reprocessing Shrinkage (3)	5.6	
Total Supply		73.1
Canadian Sales (4)	42.2	
Authorized Export Sales (5)	12.5	
Total Requirements		54.7
Reserves Surplus		18.4

(1) The total deferred reserves in Alberta are estimated to be 4.3 EJ, with 3.0 EJ expected to be connected within 25 years.

(2) Beyond economic reach reserves are estimated as 1.5 EJ for Alberta and negligible for British Columbia.

(3) Reprocessing shrinkage is calculated based on testimony that capacity would be available to reprocess all volumes leaving Alberta.

(4) Canadian sales include pipeline fuel and losses but do not include fuel used for exports. They are 25 times 1982 demand of 1.6875 EJ.

(5) Export sales reflect the maximum quantities considered exportable under existing licence conditions and include an allowance of 0.5 EJ for fuel used in Canada to export those quantities.

Table 3-14

DELIVERABILITY APPRAISAL
(Petajoules)

	Deliverability			Requirements							
	From Establ. Reserves as of 31 Dec. 1981	From Estimated Reserves Additions	Total	Canadian Net Sales	Reprocessing Fuel and Shrinkage	Pipeline Fuel (for Domestic and Export Shipments)	Maritimes Sales and Fuel	Sub Total(1)	Estimated Exports(2)	Total	Gross Deliverability Available for New Exports
1982	4 716	18	4 734	1 598	202	117	-	1 917	887	2 804	1 930
1983	5 040	62	5 102	1 651	209	127	-	1 987	1 142	3 129	1 973
1984	5 198	140	5 338	1 766	273	136	-	2 175	1 267	3 442	1 896
1985	5 082	265	5 347	1 887	281	143	2	2 309	1 290	3 599	1 748
1986	4 971	416	5 387	1 960	287	146	2	2 391	1 226	3 617	1 770
1987	4 823	576	5 399	2 049	279	146	3	2 471	1 035	3 506	1 893
1988	4 502	738	5 240	2 122	250	143	11	2 504	692	3 196	2 044
1989	4 085	897	4 983	2 202	229	143	23	2 551	538	3 089	1 894
1990	3 781	1 046	4 827	2 305	226	136	34	2 633	217	2 850	1 977
1991	3 402	1 182	4 584	2 383	220	136	39	2 700	121	2 821	1 763
1992	3 027	1 303	4 331	2 479	222	139	46	2 794	55	2 849	1 482
1993	2 680	1 407	4 088	2 561	224	144	52	2 877	47	2 924	1 164
1994	2 371	1 493	3 864	2 645	227	148	58	2 962	7	2 969	895
1995	2 136	1 562	3 698	2 732	231	153	65	3 051	6	3 057	641
1996	1 900	1 612	3 512	2 794	229	156	70	3 109	-	3 109	403
1997	1 727	1 646	3 373	2 861	233	160	75	3 179	-	3 179	194
1998	1 535	1 667	3 202	2 935	237	164	80	3 256	-	3 256	-
1999	1 364	1 675	3 039	3 014	240	169	86	3 337	-	3 337	-
2000	1 233	1 672	2 905	3 107	245	173	92	3 433	-	3 433	-

(1) For purposes of the Deliverability Appraisal this sub-total includes domestic net sales, fuel used for domestic and export pipeline transportation and reprocessing fuel and shrinkage; Maritimes requirements are excluded.

(2) Under existing licences.

Note: Figures may not add due to rounding.

CHAPTER 4
Reasons For Decisions

4.1 Introduction

Having determined that a surplus of natural gas exists, the Board had to consider:

1) Whether exporting the surplus was likely to generate gains to Canadian society greater than the costs incurred by present and future generations; and

2) Given a positive answer to the first question, how to allocate the surplus among applications for export, the total of which exceeded by a considerable margin the amount of the surplus available for export.

The answer to the first question depends on a number of factors related to the costs and prices of natural gas and other competing fuels in years to come. If surplus gas is exported, the costs to Canadians in the post-export period will be higher than they would otherwise have been. In determining whether exports are beneficial to Canadian society, therefore, the Board had to weigh all of the benefits associated with export against all of the costs.

The benefits from exports include the revenues generated by the sale of the gas and its by-products. The costs consist of the incremental costs of producing, processing, and delivering the gas to the export point, and the future cost to Canadians of having to use higher cost gas, including gas from the frontier areas, at an earlier date in the future if additional gas is allowed to be exported. If the benefits from the sale of the Canadian gas abroad exceed the sum total of the costs, Canadians are better off as a result of exporting the surplus than they would have been from keeping surplus gas in the ground.

It is important to note that a no-export policy is not a costless option, as is frequently implied in discussions of this issue. If current surpluses are not sold domestically or abroad within a reasonable time period, inventory costs for producers would continue to be excessively high. Producers (particularly those which are small and which tend to be Canadian owned) would suffer from a severely reduced cash flow and the industry generally would tend to contract. The resulting instability in industry activity would of itself tend to increase the cost of energy supply to Canadians in the long run.

To aid in its assessment of the benefits and costs to Canada from exporting surplus gas the Board has conducted a quantitative benefit-cost analysis, the results of which are reported in this Chapter.

In allocating the surplus among the large number of Applicants the Board has had to take account of a wide range of factors, both qualitative and quantitative:

- the relative magnitudes of the benefits and costs to Canadian society from individual export applications and from alternative combinations;

- the ability of existing pipeline systems to accommodate an increased flow of gas to the United States market; and

- the prospects for marketing increased volumes of Canadian gas in different United States regional markets and the attractiveness of these markets relative to the Japanese market.

The Board is cognizant of the fact that a favourable assessment of an export application from the point of view of Canadian society does not of itself guarantee that the project is desirable from the point of view of all parties directly involved - provincial governments, gas producers, owners of pipeline and/or liquefaction facilities. Benefit-cost analysis can assist in the assessment of whether a gas export application should, from a public point of view, be accepted. It may, however, be necessary to conduct further analysis of a given project, after its social desirability has been demonstrated, in order to examine whether or not, from the perspective of the private sector and any provincial governments which may be involved, the project is likely to proceed.

From a private perspective, there are a number of factors which may weigh heavily in the assessment of the viability of the project but which are of less or no significance from a social perspective. For example, the time pattern of the returns relative to the outlays involved in a project, while of some significance from the point of view of society as a whole, may be critical from a private sector perspective in order to arrange reasonable project financing. Moreover, the distribution of the returns among interested parties (including provincial governments) is of no concern to the outcome of the social benefit-cost assessment though it is clearly of great importance from the point of view of the parties involved.

In terms of this decision, these issues were most important with respect to the Dome application to export LNG to Japan. The project is analyzed from both a private and a social point of view and is compared with pipeline exports to the United States from both perspectives.

The Board has had to make its decision in this hearing in the face of an unusual degree of uncertainty which relates both to the prospects for oil prices and the prospects for market opportunities and prices obtainable for Canadian gas in the United States.

The prospects for world oil prices have changed quite dramatically over the past year. Whereas a year ago most observers were expecting continued real increases in the world price of crude oil, most are now projecting some further decline over the near term with a return to gently rising real prices only towards the end of the decade. World oil price prospects are important for this gas export decision for a number of reasons:

- the world oil price directly affects the price of oil in the United States, one of the chief competitors to Canadian natural gas;

- world oil prices directly affect 50 percent of the price escalation of the Japanese LNG sales contract; and

- world oil prices also affect the prices of Canadian-produced oil and natural gas and, as a consequence, the demand for energy, including natural gas, in this country.

In its analysis the Board assumed that world oil prices in real terms would move in a range between the price that prevailed in 1981 and a price 20 percent below that level.

With respect to United States natural gas markets the Board is acutely aware of the state of flux and uncertainty which currently exists. Dissatisfaction with the Natural Gas Policy Act, a surplus of low cost indigenous gas, and pressures for partial or full deregulation of the industry have all contributed to the uncertainty. For Canada the current United States situation has meant that it is much more difficult to sell currently authorized exports, and there is a strong downward pressure on gas prices.

The Board recognizes that how much gas is actually exported under authorized licences and the resulting benefits to Canada will be strongly influenced by the pricing régime in force during the licence period. This is a complicated issue which is being intensively studied and discussed on both sides of the border at the present time.

Notwithstanding the uncertainties which currently surround the pricing question, the Board had, of necessity, to formulate a working hypothesis for use in its analysis. The Board conducted its analysis related to this Decision on the assumption that the price of exports of Canadian gas would remain at its current level in nominal terms until the price falls to 70 percent of the United States refinery acquisition cost for crude oil. The price was assumed to be maintained at this level for the remainder of the period. The Board in using this scenario, did not necessarily deem it to be the most likely or the most desirable one. Rather, in adopting this working assumption, the Board realized that this price scenario was on the low side and that if benefits to Canada could be demonstrated under this hypothesis, there was a considerable likelihood that benefits would, in the event, be higher.

In fact, the pricing relationships likely to prevail would appear to be:

1) LNG sales to Japan at prices closer to world crude oil equivalent than the price of exports to the United States;

2) pipeline sales to the United States at prices significantly higher than those used for illustrative/analytical purposes in this Report (in its submission Dome assumed a higher export price, equal to 85 percent of oil substitution value); and

3) sales in the domestic market at prices related to the Toronto refinery gate price of Canadian crude oil which, in turn will gradually approach the world oil price.

Clearly all of these gas prices will be powerfully affected by developments in the world price of crude oil the prospects for which are very uncertain. But, as long as there is no major and prolonged further reduction in world crude prices, sales at all of these prices are likely to yield attractive netbacks.

4.2 Factors Considered by the Board in Allocation of Surplus

4.2.1 Marketability and Supply/Demand Balance

Introduction

In the period since the last Omnibus Export hearing in 1979, the Board has become increasingly concerned over the level of underlifting on certain existing gas export licences. In the 1979-80 licence year, exports amounted to only 76 percent of the authorized quantities and in the 1980-81

licence year only 54 percent of authorized volumes in licences were exported. Exports in this past licence year ('81-'82) were some 47 percent of authorized. While some of the underdeliveries can be attributed to delays in the start-up of some new licences, it is also clear that fundamental market factors in the United States, namely the level of gas demand, the availability of supplies of United States indigenous natural gas and the price of Canadian imports relative to United States gas and other energy forms, are having a significantly depressing effect on the demand for Canadian gas.

Regarding the first factor, the Board notes that overall demand for gas in the United States, as reported by the United States Department of Energy, has been declining steadily for the past several years. Since 1976 demand has fallen at a rate of approximately one percent per year. Reserves of discovered gas, on the other hand, which had been declining by about two percent per year have begun to stabilize in the last two years. The combination of those two factors has resulted in a surplus of indigenous gas in the United States.

The Board recognizes the importance of the competitive price factor, but the main purpose of the Hearing was related to decisions on the granting of export licences rather than focussing on the appropriate price régime for exports of natural gas by Canada. Cognizance had to be taken, however, of the general pricing situation.

The Board invited Applicants to address the question of marketability of Canadian gas. The Board has used this evidence in making its judgement on, firstly, the overall potential market likely to be open to Canadian gas, and secondly, the regions within the United States which would be most receptive to new exports of gas from Canada.

4.2.1.1 United States Market Overview

The Board received evidence on the United States market outlook to the year 2000 from three Applicants, TransCanada, ProGas and Pan-Alberta. Dome filed evidence which dealt with the period up to 1985.

Because of the difference in assumptions pertaining to crude oil prices, the supply/demand estimates are not directly comparable. However, the Board has found these projections useful in determining a probable range for the potential market available to Canada. To accomplish this the Board has taken the low crude oil price scenario in each of the studies and determined the range of projections based on the high and low estimate in the studies for each of the following: United States production from lower-48 conventional sources, United States lower-48 demand and supplemental gas requirement, (i.e., that amount of gas required from other sources, such as Alaska, imports of gas from Canada and Mexico, imports of LNG, synthetic gas etc. to balance the demand). Intervenors, for the most part, did not challenge the projections put forth by the four submittors.

Demand

Submittors generally were of the view that little growth in demand for natural gas would occur during the forecast period. A rapidly rising real price for gas coupled with conservation and a relatively low rate of economic growth should hold down demand growth in the residential and commercial sectors. In the industrial sector, opportunities will exist for utilizing less expensive energy forms, notably coal and residual fuel oil.

The range of projections put forth are as follows:

United States Lower-48 Demand
(Exajoules)

	Range of Submittors' Projections
1981	20.3 (Actual)
1985	20.3 - 24.1
1990	19.7 - 21.5
1995	19.4 - 21.9
2000	19.1 - 22.9

The Board, while accepting the projections, takes note of the degree of uncertainty in submittors' forecasts.

Production

Projections for lower-48 conventional gas production indicate a steady level up to 1985 and then show a marked decline. Submittors (with the exception of Dome which did not study the period beyond 1985) held the view that while drilling activity would likely remain fairly stable, the productivity of drilling (gas discovered per foot drilled) would continue to decline steadily, resulting in declining reserves. TransCanada's evidence suggested that United States conventional reserves could decline from 166 EJ currently to a level of about 160 EJ in the late 1980's and 128 EJ by 2000.

While most submittors felt that decontrol[1] of United States wellhead prices would have a positive effect on drilling activity, they did not view this prospect as arresting the overall downward trend in reserves additions. Dome's evidence, to the contrary, suggested that decontrol would result in a dramatic upsurge in drilling activity to the point where annual reserves additions would equal or exceed annual production. The Dome witness reinforced this position, noting that earlier projections by many analysts had underestimated the level of drilling and reserves additions that have been attained under NGPA ceiling price controls. Therefore, with deregulation United States natural gas supply potential may be greater than previously anticipated.

Dome further argued that the current "gas supply bubble" or excess deliverability in the United States would remain for some time and could, in fact, increase as a result of increased drilling activity expected with decontrol.

While the Board accepts the production estimates as put forward by the submittors, it recognizes the Dome argument and therefore gives greater weighting to the upper bound of the production estimate range, which follows:

(1) The Natural Gas Policy Act of 1978 provides for the partial decontrol of wellhead prices between 1985 and 1987.

United States Lower-48 Production
(Exajoules)

	Range of Submittors' Projections
1981	19.8 (Actual)
1985	18.0 - 22.1
1990	16.8 - 16.9
1995	15.7 - 16.6
2000	11.5 - 15.6

Supply/Demand Balance

Table 4-1 draws together the projections of production, demand and the resultant range of supplemental requirement forecast by the submittors.

Sources of Supplemental Supply

Submittors provided evidence on the possible sources of supplemental gas supplies to the United States market. Projections of individual sources of supply tended to vary greatly and rested heavily on assumptions made as to, for example, the prospect for completion of the ANGTS. The Board therefore has made its own projection of supplemental supplies to the United States based on its assessment of the evidence.

Alaskan gas is presumed to start flowing in 1989 with volumes in the range of 0.7 to 0.9 EJ per year. It is thought that United States regulatory authorities will accord this source some form of preferential regulatory treatment to ensure its marketability.

Mexican gas imports to the United States currently

Table 4-1

UNITED STATES LOWER-48 SUPPLY/DEMAND

(Exajoules)

	Actual	Range of Submittors' Projections			
	1981	1985	1990	1995	2000
Production	19.8	18.0-22.1	16.8-16.9	15.7-16.6	11.5-15.6
Demand	20.3	20.3-24.1	19.7-21.5	19.4-21.9	19.1-22.9
Supplemental Requirement	0.5	0-3.5	2.9- 4.7	3.7- 5.9	5.3- 8.2

run about 100 PJ per year, purchased mainly by Tenneco, Texas Eastern and El Paso. The future of Mexican gas is uncertain. Consequently, estimates of future exports to the United States vary widely. The Board believes that Mexico will endeavour to increase its share of the United States market at a moderate but steady pace, reflecting its anticipated growth in surplus gas availability. It is expected that this could result in a doubling of exports to about 230 PJ by 1985 and a further doubling to 460 PJ by 1995.

LNG has been imported on an ongoing basis by the Boston Distrigas utility which purchases approximately 45 PJ per year. At this time, resumption of deliveries to Cove Point, Maryland by the El Paso group appears unlikely. However, it appears as though the Trunkline project may be reactivated with one shipment recently having been received at the Lake Charles, Louisiana terminal. The Board believes that the United States will continue to import some amounts of LNG even though prices may be uncompetitive with domestic United States sources at this time. The level of import is expected to be 45 PJ and 120 PJ per year for Distrigas and Trunkline respectively.

Synthetic gas production in the United States was about 105 PJ in 1981, with over one half coming from one plant, Columbia LNG Corp., at Green Springs, Ohio. The Board considers the prospect of substantial new SNG capacity coming on stream in the near future to be doubtful. However, it is felt that production from existing plants will continue at or near current levels.

Similarly, it is felt that coal gas and gas from new technologies will remain out of economic reach during the period under consideration.

Drawing from all of the above, the Board is able to reach some conclusions as to the probable range of United States demand for Canadian gas over the next 18 years, as shown in Table 4-2.

From the evidence, it is apparent that the market opportunities for Canadian gas in the United States in the short run are not particularly encouraging. The prospect of the current United States surplus deliverability situation extending into the second half of the decade now seems likely. Accelerated decontrol of United States gas prices, as argued by Dome, could further improve the United States supply position, particularly in the mid-to late 1980's.

Taken over the longer term, the United States market offers substantial opportunity to Canada for expanded exports. Moreover, the Board is aware that certain regions of the United States could exhibit greater potential for Canadian exports than the national outlook would suggest. The regional aspect is discussed more fully in later sections.

Pricing of Canadian Gas

Submittors were agreed that Canadian gas imports would meet increasing competition from domestic United States gas and from alternate fuel, mainly residual oil. The downward pressure on the Canadian price is expected to intensify with the partial decontrol of United States wellhead prices in the 1985-87 period. TransCanada's submission stressed that there is no consistent relationship between the Canadian border price/world crude price ratio and the demand for gas in the United States; and that maintaining a fixed price ratio could lead to wide swings in the demand for Canadian gas. It further argued that under United States deregulation, it is highly probable that the price of Canadian gas at the city gate would have to equal the price of gas from other sources.

Price controls have resulted in large amounts of United States production being priced below levels which might otherwise have been attained. This has afforded the interstate pipelines the opportunity to augment their supplies of gas from higher cost sources, such as Canada, while still maintaining their average city gate price at a competitive level with alternative fuels. This ability to "roll-in" Canadian gas, while not disappearing entirely, would be greatly reduced when wellhead price controls start to come off in 1985.

4.2.1.2 Regional United States Markets

The Board received evidence from Applicants and their customers concerning the marketability of Canadian gas in those markets now receiving gas from Canada and in new markets requesting gas from Canada. The Board has found this evidence to be useful in reaching its decision on which United States markets would be most receptive to new exports from Canada. A summary by region of the key issues raised follows:

Table 4-2

POTENTIAL DEMAND FOR CANADIAN GAS IN THE UNITED STATES

(Exajoules)

	1985	1990	1995	2000
Supplemental Requirement	0-3.5	2.9-4.7	3.7-5.9	5.3-8.2
Supplemental Supply - Alaska	-	0.80	0.80	0.80
- Mexican	0.23	0.34	0.46	0.46
- LNG	0.16	0.16	0.16	0.16
- SNG	0.10	0.10	0.10	0.10
	0.5	1.4	1.5	1.5
Potential for Canada	0-3.0	1.5-3.3	2.2-4.4	3.8-6.7
Deduct: Currently Licensed Volumes	1.6	0.2	0.	0.
Potential for New Exports	0-1.4	1.3-3.1	2.2-4.4	3.8-6.7

United States Markets Served by Existing Exporters(1)

Pacific Region

Northwest

The Canadian exporter to this region is Westcoast and its United States buyer is Northwest Pipeline. As pointed out in the evidence of Northwest Pipeline, the Pacific Northwest region has historically relied upon Canada for up to 60 percent of its gas supply. In the last two years this reliance has decreased but is still in excess of 50 percent. Furthermore, Northwest Pipeline and the Northwest Distributors stated that competition from low cost high sulphur No. 6 fuel oil in the industrial sector and low cost hydroelectric power in the residential and commercial markets have contributed to the erosion of the share of the energy market held by natural gas.

California

Northern California is served by PG&E which purchases Canadian gas from A&S through its subsidiary PGT. As noted by PG&E, it has in the past purchased in excess of 30 percent of its gas supply from Canada but due to restrictions imposed by the California Public Utilities Commission (CPUC), it has reduced the import level of Canadian gas into California by some 3 400.0 x $10^3 m^3$ per day. These restrictions have recently been extended for a second two-year term to 30 June 1984 and are incorporated in the A&S/PGT export contract. The CPUC has directed the distributors to rely on the least-cost

(1) The breakdown by state of the various regions is shown on Table 4-3.

Table 4-3

REGIONAL UNITED STATES MARKETS - RANKING CRITERIA

	Natural Gas Share of Market (Stationary Use) - 1980	
	%	Rank (inverted)
New England	14.2	1
Mid-Atlantic	23.6	2
East-North-Central	33.1	4
West-North-Central	33.3	5
Mountain	27.2	3
Pacific	35.2	6

	Residential Oil to Gas Conversions - 1980 (1)				
	No. of Conversions		Rate of Conversion		
	(000's)	Rank	(Percent)	Rank	Average Rank
New England	63.5	3	3.6	1	2
Mid-Atlantic	212.2	1	2.6	2	1
East-North-Central	164.9	2	1.5	3	3
West-North-Central	28.4	4	0.7	4	4
Mountain	2.6	6	0.1	6	6
Pacific	19.9	5	0.2	5	5

	Oil Share of Market (Stationary Use) - 1980						
	Residential		Commercial		Industrial		Average
	%	Rank	%	Rank	%	Rank	Rank
New England	57.4	1	43.2	1	56.4	1	1
Mid-Atlantic	33.2	2	36.2	2	35.8	2	2
East-North-Central	15.0	4	8.9	3	10.6	5	3
West-North-Central	18.9	3	8.9	4	8.4	6	4
Mountain	11.3	5	5.9	6	18.2	3	5
Pacific	8.8	6	7.2	5	12.0	4	6

	Estimated Comparative Advantage at the Burner Tip Gas Over Oil - 1985 (2) (Percent)			
	Residential	Commercial	Industrial	Rank
New England	10	9	0	6
Mid-Atlantic	17	14	9	5
East-North-Central	52	50	28	3
West-North-Central	61	60	45	1
Mountain	57	55	34	2
Pacific	47	41	17	4

(1) Conversion activity has been approximately equal to new construction activity. Although population changes have been favouring Southern and Western regions, the high concentration of conversion activity in the Northeast far outweighs the population shift advantage.

(2) The comparison is made with #2 fuel oil in residential and commercial sections, #6 low sulphur residual fuel oil in the industrial sector in the New England and Mid Atlantic regions, and #6 high sulphur residual fuel oil in the industrial sectors of the East North Central, West North Central, Mountain and Pacific Northwest regions.

New England: Connecticut, Maine, Massachusets, New Hampshire, Rhode Island, Vermont
Mid-Atlantic: New Jersey, New York, Pennsylvania
East-North-Central: Illinois, Indiana, Michigan, Ohio, Wisconsin
West-North-Central: Iowa, Kansas, Minnesota, Missouri, Nebraska, North Dakota, South Dakota
Mountain: Arizona, Colorado, Idaho, Montana, Nevada, New Mexico, Utah, Wyoming
Pacific: California, Oregon, Washington

source of supply to the greatest extent possible. This means purchasing more United States indigenous gas.

Southern California is supplied with Alberta gas sold through the Foothills Western Leg prebuild pipeline and exported to Southern California by displacement. The Canadian exporter is Pan-Alberta and the United States importer is Northwest Alaskan which re-sells the gas to Pacific Interstate for subsequent delivery to SoCal.

Sales of Canadian gas to this market area began in September 1981 but have not exceeded the minimum contract quantity. The reason for this, according to testimony by Pacific Interstate, was a directive from the CPUC to ensure that gas distributors purchase the least-cost source of supply within their contractual limitation.

Mountain Region

In 1981 the Montana market served by exporter Canadian-Montana received 52 percent of its gas supply from Canada. The United States importer in this region is Montana Power. Sales to Montana have recently declined due to the loss of large industrial accounts and conversion to other fuels, particularly to coal, according to the evidence of Canadian-Montana.

West-North-Central and East-North-Central Regions

These two regions are also known as the Midwest market area. Importers of Canadian gas to this region serve mainly the States of North Dakota, Minnesota, Iowa, Illinois, Indiana, Michigan and Wisconsin. Major market centres are Minneapolis-St. Paul, Chicago, Detroit, and Milwaukee. Canadian exporters to the Midwest at Emerson, Manitoba are TransCanada, Consolidated and ProGas. The gas is sold to Michigan Wisconsin, Northern Natural, Great Lakes, Natural Gas Pipe and Midwestern. Canadian gas destined for the Midwest by exchange is exported at Monchy, Saskatchewan by ProGas, Consolidated and Pan-Alberta through the Northern Border system.

Historically, this region has accounted for approximately 28 percent of total Canadian natural gas exports. The share of market held by Canadian gas ranges from about four percent in Illinois to 20 percent in North Dakota. Midwestern's northern system, which serves customers in Minnesota, Wisconsin and North Dakota, is 100 percent dependent on Canadian supply for historic, practical and economic reasons.

All of the United States importers attested to the fact that their takes of Canadian gas had been at or near the maximum licence quantities prior to 1981. However, in the last two years sales have been reduced and the importers stated that this was due mainly to the economic situation in the United States, conservation that has taken place in the wake of price increases for gas supply, and intense price competition from alternative energy forms, particularly in the industrial sector.

New England and Mid-Atlantic Regions

These two regions are also known as the Northeast market area. Canadian gas currently does not account for any significant portion of natural gas sales in this region. Two exporters to this region are Niagara Gas exporting at Cornwall, Ontario to St. Lawrence Gas and TransCanada exporting at Phillipsburg, Quebec to Vermont Gas. Both of these sales are border accommodations and the markets are entirely dependent on Canada for their gas supply.

Niagara Gas' evidence indicated that sales to St.Lawrence Gas have declined due to the loss of industrial load to other fuels. In the Vermont market sales remain fairly static due to its high residential and commercial make-up.

Sulpetro and Union Gas both export to Transco at Niagara Falls and Windsor, Ontario respectively. The gas is delivered to the Mid-Atlantic region by displacement.

New United States Markets Proposed to be Served from New Exports

Pacific and Mountain Regions

With the exception of Texas Eastern and Transwestern all submittors rated the California, Pacific Northwest and Montana markets as having little growth potential over the next several years. Texas Eastern and Transwestern testified that they saw great potential for taking Canadian gas at high load factors at an early date, particularly in view of Transwestern's low reserve life ratio of 4.5 years. In terms of gas market share, Applicants did not anticipate significant changes to take place in the near term. Over a longer term gas markets are expected to show some moderate growth except in Montana, where no growth is anticipated for the rest of this century. However, Pan-Alberta testified that the need for Canadian gas in its United States

markets will continue even after Alaskan gas begins to flow in 1989.

Northwest Distributors testified that there are excellent prospects for further market penetration by British Columbia gas. Panhandle supported the position taken by the Northwest Distributors.

Generally, the alternative fuels to gas in the high priority markets are distillate fuel oil (No. 2 fuel oil) and electricity. In the large industrial markets the alternative fuel is heavy fuel oil (No. 6 fuel oil). High environmental standards in California severely restrict the use of No. 6 fuel oil in the industrial sector. PG&E testified that there is no viable substitute for Canadian gas in the California market. Similarly, Canadian-Montana stated that there was no suitable alternative to Canadian gas in its market.

Turning to burner-tip cost comparison, Northwest stated that competition from electricity in the Pacific Northwest will abate as major hydropower sites become fully utilized and present hydropower based rates rise from 1.0 - 1.5 cents per kW.h., (\$2.93 - \$4.00 per MMBtu) to 7.0 cents per kW.h., (\$20.50 per MMBtu). Northwest also testified that gas prices in the residential and commercial sector, ranging from \$5.50 to \$6.00 per MMBtu, were assumed to remain competitive with No. 2 fuel oil prices of \$6.25 per MMBtu. Under this assumption, residential and commercial requirements were projected to increase at approximately three percent per year. If regulations to conserve electricity are also adopted and if natural gas prices remain competitive, the growth in residential use of natural gas could increase as much as seven percent per year. Northwest Distributors' testimony indicated that No. 6 fuel oil is the strongest competitor in the industrial sector; however, under favourable pricing conditions natural gas has the potential to displace 30 Bcf of fuel oil equivalent. Northwest Distributors also maintained that with increasing electricity rates and a stable Canadian gas price, the region could again achieve and maintain satisfactory takes of Canadian gas.

West-North-Central and East-North-Central Regions

Whereas evidence submitted on behalf of certain importers to the New England, Mid-Atlantic and Pacific regions tended to show a potential for natural gas growth, the Midwest regions differ in that importers do not expect incremental gas sales to occur to any large extent. Natural Gas Pipe projected modest growth in its new residential and commercial markets. In support of its contention, Natural Gas Pipe stated that of new sales it proposed to make, approximately 78 percent would be made to an existing distribution company in the Gulf Coast area while only 22 percent of the gas would go to seven existing customers in the Midwest region.

Northern Natural advised that it was faced with softening markets due to the recession and its effects on industrial demand. Expectations are for market load profiles to remain virtually unchanged over the next 20 years. The Company indicated that any new growth would be offset by a reduction due to conservation.

The Midwest importers agreed that the predominant alternative fuel in the industrial market was and would continue to be residual fuel oil. Michigan Wisconsin added that some large industrial customers have converted to coal and others are likely to follow suit. In the residential and commercial markets the primary competition was said to be No. 2 fuel oil. Natural Gas Pipe added that some competition could be expected from heat pumps.

With regard to burner-tip cost comparisons, Natural Gas Pipe said that the cost of gas in the industrial market in the Chicago area was very close to that of residual fuel oil and the Company felt that it was reaching the point where fuel switching could take place, particularly in the dual fuel markets. Michigan Wisconsin stated that the market clearing price for gas would be that of residual fuel oil.

While none of the Midwest importers forecast significant increases in natural gas demand, they all pointed to projected declines in supply as being the primary cause for their need for new Canadian supplies. Midwestern testified that in the event Canadian supply decreased, it would be forced to curtail all of its industrial customers and most of its commercial customers. Michigan Wisconsin's evidence was that in the medium and long-term outlook, Canadian supply would continue to provide a substantial portion of its requirements. Natural Gas Pipe stated that it needed Canadian supply to satisfy its existing and estimated future requirements provided such supply could be blended into its overall supply mix thereby allowing

Canadian gas to remain competitive in its market area.

Mid-Atlantic and New England Regions

In general, submittors rated the Mid-Atlantic and New England markets as having a greater gas market potential than any other United States market region. In terms of gas market shares Transco testified that because of the relatively low saturation level of gas space-heating in its market area, the high priority residential and commercial market was expected to grow at an annual average rate of 1.3 percent, while total United States gas demand for these markets was expected to remain relatively stable for the rest of the century. Similarly, Boundary noted that the gas market share for these markets was only nine percent compared to a national average of 25 percent.

Tennessee testified that the alternative fuels to gas in the high priority markets are No. 2 fuel oil and electricity with heavy fuel the alternative for the large industrial market. It further noted that 91 percent of its requirement was for high priority loads. Tetco stated that the price of fuel oil tends to be higher in the United States East Coast market areas than in other parts of the United States because the consumption of fuel oil is substantially greater than local production. This was supported by Boundary which observed that the Northeast market with its high value alternative fuels was better able to absorb Canadian gas at its present price of $4.94 U.S. per MMBtu than any other market area in the United States.

Boundary also supported the results of TransCanada's study as to the potential for increased gas sales in its market area. Pan-Alberta and ProGas also supported this position as did Dome which acknowledged that the eastern market held the best potential of all markets in the United States. Historically this region has been highly dependent upon foreign oil; as noted by Algonquin, some 75 percent of heating customers in the region cannot be served by gas for lack of supply.

Another issue raised by importers was the impact of rolling-in Canadian supply with United States supply, both in terms of market penetration and pricing. Tennessee noted that it was purchasing Canadian gas for its entire system and, that the price of Canadian gas was expected to be rolled into their system price. Transco noted that while Canadian gas would be treated as rolled-in supply it was technically subject to the so-called incremental pricing provision of the NGPA.(1) Most importers agreed that Canadian gas would continue to receive rolled-in treatment by FERC and that this would aid its marketability.

The Board's Assessment

The Board's assessment of market factors must ultimately be based on judgment founded on the evidence. To assist it in arriving at a decision, the Board assessed the evidence with respect to each of the broad United States market areas which would be served by imports of Canadian gas and ranked them according to four criteria which were indicated by the participants as being indicative of the growth potential, ability to absorb, and receptiveness to Canadian gas. These are:

1. the present share of natural gas in the market (indicating the potential for further gas penetration);

2. the current level at which residential customers in a market are switching from oil to gas (indicating the rate of penetration in a high value and stable market segment);

3. the present share of the market supplied by fuel oil (indicating the opportunity for oil displacement); and

4. the anticipated burner tip comparative cost advantage of gas over oil (indicating the competitive advantage held by gas).

Following are the individual rankings as determined for each of the four criteria examined (refer also to Table 4-3) and the average rank. The average ranking was then converted into an index of relative attractiveness of the market.(2)

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(1) The incremental pricing provision of the NGPA requires that Canadian gas sold in the United States be priced at its full cost including transportation to the city gate.

(2) Table 4-4 gives a breakdown of the destinations of gas for new licence applications.

Table 4-4

DESTINATIONS OF GAS FOR NEW LICENCE APPLICATIONS
(First Full Volume Year)
($10^6 m^3$/year)

Exporter - Importer	New England		Mid-Atlantic		East-North-Central		West-North-Central		Pacific	
TCPL - Texas Eastern			955	91%	85	9%				
TCPL - Transco			3 110	100%						
TCPL - Mich. Wisc.					995	95%	45	5%		
TCPL - Boundary	525	28%	1 360	72%						
TCPL - Natural Gas Pipe					938	90%	102	10%		
TCPL - Tennessee 1	365	35%	402	38%	275	27%				
- Tennessee 2	730	35%	804	38%	550	27%				
KannGaz - Tennessee	454	35%	497	38%	340	27%				
ProGas - Texas Eastern			950	91%	85	9%				
ProGas - Texas Gas					1 920	100%				
ProGas - Transwestern									655	100%
Sulpetro - Transco			770	100%						
Pan-Alberta-Algonquin (approximated)	350	33%	700	66%						
Pan-Alberta - Texas Eastern			970	91%	85	9%				
Pan-Alberta - Transco			1 050	100%						
Ocelot - Tennessee	345	35%	380	38%	260	27%				
Cdn.-Montana - Tennessee	253	35%	275	38%	196	27%				

Ranking Under Marketability Criterion

	Natural Gas Share Of Market	Oil To Gas Conversions	Oil Share Of Market	Comparative Cost Advantage Of Gas	Average Rank
New England	1	2	1	6	2.5
Mid-Atlantic	2	1	2	5	2.5
East-North-Central	4	3	3	3	3.3
West-North-Central	5	4	4	1	3.5
Mountain	3	6	5	2	4.0
Pacific	6	5	6	4	5.3

Index of Relative Attractiveness of the Market

New England	1
Mid-Atlantic	1
East-North-Central	3
West-North-Central	4
Mountain	5
Pacific	6

A comparative ranking of each application for a new export licence was then determined by applying an estimate of the regional distribution for each application to the combined rank.

Ranking of Applications for New Export Licences According to United States Market Factors(1)

Rank	Exporter	Importer
1	TCPL	Transco
1	TCPL	Boundary
1	Sulpetro	Transco
1	Pan-Alberta	Algonquin
1	Pan-Alberta	Transco
2	TCPL	Texas Eastern
2	ProGas	Texas Eastern
2	Pan-Alberta	Texas Eastern
3	TCPL	Tennessee 1
3	TCPL	Tennessee 2
3	KannGaz	Tennessee

(Continuation: Ranking of Applications)

3	Ocelot	Tennessee
3	Cdn-Montana	Tennessee
4	ProGas	Texas Gas
5	TCPL	Michigan Wisconsin
6	TCPL	Natural Gas
7	ProGas	Transwestern

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(1) The bases on which these rankings were determined is as follows:

1. that Canadian gas delivered to New England and Mid-Atlantic regions would pay the full cost applicable to the Niagara Joint Venture Pipeline;

2. United States gas delivered to these regions would pay the current rates escalated according to evidence submitted;

3. the city-gate price in these regions would be the rolled-in cost of Canadian and United States supply;

4. new Canadian licenced exports would be comingled with existing supply and distributed in the market in the same proportion as all other sources of supply;

5. the United States pipeline network is sufficiently flexible to ensure that potential gas shortages would be national shortages, not regional shortages.

There are, of course, other regional factors which have to be taken into account, such as the cost of the gas supply available to the pipeline company supplying the market, the relative mix of customers between residential, commercial and industrial, and the price and availability of residual oil over time.

Concerning the latter two factors, the evidence available from the filed studies indicates that the New England and Mid-Atlantic regions have a larger proportion of high priority, residential and commercial demand, typically in the range of 70 to 90 percent of total sales as compared with 40 to 70 percent in the other regions. Transco, as noted earlier, testified that while it expects no growth in residential and commercial demand in the rest of the United States, it is forecasting an annual average growth of 1.3 percent in New England. Moreover, interfuel competition from lower cost, high sulphur residual oil, as testified to by Tetco and Boundary, is less pronounced in these regions. Both of these factors are regarded as being favourable to Canadian gas. Based on the evidence, the principal sources of competition to gas are as follows:

Principal Alternative Energies to Gas

Region	Residential and Commercial	Industrial
New England	#2 fuel oil and electricity	#6 low sulphur
Mid-Atlantic	#2 fuel oil and electricity	#6 low sulphur
East-North-Central	#2 fuel oil	#6 high sulphur
West-North-Central	#2 fuel oil	#6 high sulphur
Mountain	#2 fuel oil and electricity	#6 high sulphur
Pacific Northwest	#2 fuel oil and electricity	#6 high sulphur
California	#2 fuel oil and electricity	#6 low sulphur

4.2.1.3 United States Importers and Cost of Transmission

Also of concern to the Board in its consideration of licensing new exports of natural gas is the expected ability of the United States importing company to take the applied-for volumes of gas which would also include its ability to "offline" volumes to other pipelines should its gas supply position be in surplus at times. This requires a consideration of the following three factors:

1. the importer's supply/demand position with respect to the need for supplemental gas;
2. the importer's geographic area of coverage and interconnection with other interstate systems; and
3. the cost of transporting gas from the Canadian border to the load centre.

Regarding the first factor the following grouping of importers (refer also to detailed Table 4-5) according to their filed forecasts of requirement for additional supply during the period 1984 to 1994, is made(1):

Grouping of Importers According To Their Indicated Supply Deficiency - 1984-1994

Group A
(importers showing a requirement for 75 - 100 x $10^9 m^3$)
- Northwest Alaskan at Monchy to (Panhandle
(Northern Natural
(United

Group B
(importers showing a requirement for 50 - 74 x $10^9 m^3$)
- Transco
- Texas Gas
- Tennessee

Group C
(importers showing a requirement for 25 - 49 x $10^9 m^3$)
- Texas Eastern
- Boundary

(1) Including all sources of supplemental supply included by the importer in its submission.

Table 4-5

UNITED STATES IMPORTERS' FORECAST SUPPLY DEFICIENCY (SURPLUS)(1)
($10^9 m^3$)

Importer	Exporter	1984	1985-89	1990-94	Total 1984-1994
Tennessee	ProGas, TCPL, KannGaz, Ocelot, Cdn.-Montana	(0.2)	16.1	49.4	65.3
Natural Gas Pipe	ProGas, TCPL	-	-	-	-
Michigan Wisconsin	ProGas, TCPL	-	(0.8)	0.9	0.1
Transco	Union, TCPL, Sulpetro, Pan-Alberta	3.6	14.4	41.0	59.0
Midwestern	TCPL	-	-	-	-
Texas Eastern	ProGas, Pan-Alberta TCPL	1.6	9.2	35.8	46.6
Boundary	TCPL	(0.5)	8.8	31.9	40.2
PGT(1)	A&S	(5.8)	(26.3)	(31.0)	(63.1)
Panhandle) Northern Natural) United)	Pan-Alberta to Northwest via Monchy	0.7	30.0	46.5	77.2
SoCal	Pan-Alberta to Northwest via Kingsgate	0.3	6.5	7.0	13.8
Transwestern	ProGas	-	-	-	-
Texas Gas	ProGas, WTCL, Columbia	(0.8)	24.1	45.4	68.7
Northwest Pipeline	WTCL	-	0.1	4.4	4.5
Montana Power	Cdn.-Montana	-	-	-	-
St. Lawrence Gas	Niagara	-	-	-	-
Algonquin	Pan-Alberta	-	-	1.6	1.6

(1) Including all potential sources of supplemental supply included by the importer in its submission.

Group D
(importers showing a requirement
for 1 - 24 x $10^9 m^3$)

- Michigan Wisconsin
- Algonquin
- Northwest Alaskan at Kingsgate to SoCal
- Northwest Pipeline

Group E
(importers showing a surplus
or no requirement)

- Natural Gas Pipe
- Midwestern
- PGT
- Transwestern
- Montana Power
- St. Lawrence Gas

Looking at the second factor, the United States importers are ranked in four major groupings according to the degree of geographic coverage and interconnection with other interstate systems. These groupings range from A, major pipeliners serving broad geographic markets including five or more interstate pipelines, to D, pipelines with limited markets and access to other pipelines. The importers are grouped as follows:

Grouping of Importers According to
Geographic Coverage and Connections
With Other Pipelines

Group A - Broad geographic coverage with access to five or more interstate pipelines
1. Tennessee
2. Texas Gas
3. Transcontinental

Group B - Broad geographic coverage with access to two to four interstate pipelines
1. Michigan Wisconsin
2. Natural Gas Pipe
3. Northern Natural
4. Texas Eastern
5. United

Group C - Limited geographic coverage
1. Northwest Pipeline
2. Panhandle
3. PGT
4. Southern California
5. Transwestern

Group D - Specific geographic coverage with limited access to interstate pipelines
1. Algonquin
2. Boundary
3. Midwestern
4. Montana Power
5. St. Lawrence Gas

Finally, the Board's estimate, based on the evidence, of the cost of moving gas from the international boundary to the market is shown in Table 4-6. From this information the Board is able to make a general assessment of the relative attractiveness of the various United States markets based on the cost of moving the gas to those markets as follows:

	Estimated Average Tariff-1984 ($U.S./Mcf)
West-North-Central	0.60
East-North-Central	1.15
Pacific/Mountain	1.20
Mid-Atlantic	1.30
New England	2.00

4.2.2 Supply Under Contract

Where applicable, each Applicant provided detailed estimates of its gas reserves under contract. Consolidated, Niagara Gas and Dome do not purchase gas in the field; rather, they have gas purchase agreements with TransCanada to buy gas from its contracted supply.

The Board has analysed each Applicant's contracted supply and prepared its own estimates of the Applicant's remaining gas reserves under contract. A comparison of the Applicants' and Board's estimates of remaining reserves under contract as of 31 December 1981 is presented in Table 4-7.

The Board has assessed each Applicant's ability to meet its total requirements taking into account its domestic and other sales commitments, its existing and applied-for exports, associated pipeline fuel and losses, and reprocessing shrinkages where appropriate. Not all Applicants made proper allowance for fuel and losses and reprocessing shrinkages in estimates of their requirements which, in some cases, are underestimated by as much as 10 to 15 percent. These are requirements which must be satisfied in moving the gas to market.

A comparison of the Applicants' and Board's assessments covering the time period illustrated in each application is presented in Table 4-8. The Board has adjusted the TransCanada and Westcoast supply forecasts in order to exclude uncontracted trend gas included in their assessments. TransCanada included growth on current contract lands in its supply forecast and Westcoast included all British Columbia future reserves additions in its forecast.

Although the Board's assessment shows that most Applicants are unable to meet their requirements from their contracted reserves for the full term of the licences sought, the Board is satisfied that those Applicants who receive licences will be able

Table 4-6

COST OF TRANSPORTATION TO NEW MARKETS[1]

Exporter	Importer	Service Area	Estimated Tariff - 1984 ($U.S./Mcf)	
From Border Point: Niagara Falls				
1. KannGaz, Ocelot, TransCanada, Cdn.-Montana	Tennessee a) via Niagara Joint facility (NJVF) to East Aurora, N.Y.	NE/MA	to Tennessee's	
			- Niagara zone	0.21
			- New-York zone	1.44
			- New-England zone	2.16
	or			
	b) via NJVF to Coudersport, Penn.		to Tennessee's	
			- Niagara zone	0.38
			- New-York zone	1.61
			- New-England zone	2.33
2. Pan-Alberta	Transco	MA	0.99	
	Tetco	MA/ENC	0.48	
	Algonquin	NE/MA	1.44	
3. Sulpetro	Transco	MA	0.99	
4. TransCanada	Boundary	NE/MA	same as 1.	
5. ProGas	Tetco	MA/ENC	0.55	
From Border Point: Emerson				
1. Consolidated	Northern Natural	ENC/WNC	0.22	
2. ProGas	Tennessee	NE/MA	0.91	
	Tetco	MA/ENC	1.37	
	Mich-Wisc.	ENC	1.20	
	TexasGas	ENC	1.30	
3. TransCanada	Natural Gas Pipe	ENC	0.74	
	Midwestern	WNC	0.29	
	Mich-Wisc.	ENC	1.01	
From Border Point: Monchy				
1. Westcoast	TexasGas	ENC	2.35	
2. Consolidated	Northern Natural	ENC/WNC	1.35	
3. ProGas	Natural Gas Pipe	ENC	1.75	
From Border Point: Kingsgate				
1. ProGas	Transwestern	PAC/WNC	1.16	
From Border Point: Huntington				
1. Westcoast	Tetco	MA/ENC	1.47	
	Transwestern	PAC/WNC	1.20	

NE - New England
MA - Mid-Atlantic
ENC - East-North-Central
WNC - West-North-Central
PAC - Pacific

(1) Based on an assessment of evidence filed by the Canadian exporters and the U.S. importers.

Table 4-7

CONTRACTED SUPPLY

REMAINING RESERVES AS OF 31 DECEMBER 1981

($10^6 m^3$)

Applicant	Applicant's Estimate	NEB Estimate
Alberta & Southern	191 727	166 552
Canadian-Montana	5 536	5 291
Columbia	9 006	4 513
KannGaz	24 872	17 005
Ocelot	22 123	12 459
Pan-Alberta (P.A. 80-3)	37 027	25 403
Pan-Alberta (P.A. 81-4)	203 974	133 980
ProGas 1 (GL-56)	53 081	47 471
ProGas 2 (new)	55 417	40 215
Sulpetro (new)	6 784	5 541
TransCanada	863 688	636 696
Westcoast (GL-41)	251 906	256 639

Note: Consolidated, Niagara Gas and Dome purchase their supply from TransCanada.

Table 4-8

CONTRACTED SUPPLY

ADEQUACY OF DELIVERABILITY TO MEET REQUIREMENTS(1)

(percent)

Applicant	Period	Applicant's Estimate	NEB Estimate
Alberta & Southern	1982-2000	71.8	66.2
Canadian-Montana(2)	1982-2000	72.1	88.9
Columbia	1982-1997	100.0	54.1
KannGaz	1984-1998	99.4	66.7
Ocelot	1985-2000	100.0	67.4
Pan-Alberta	1982-1995	80.7	61.6
ProGas	1982-1997	87.7	64.7
Sulpetro	1983-1990	78.3	67.1
TransCanada(3)	1982-2000	65.5	52.9
Westcoast (GL-41)(4)	1982-2000	81.1	74.2

(1) Requirements include applied-for exports.
(2) Aden area only. Canadian-Montana purchases most of its supply from Alberta and Southern.
(3) Supply adjusted to remove growth on contracted lands.
(4) Supply adjusted to remove trend gas.

to contract for sufficient additional gas to meet their requirements.

Related to supply contracting matters, the Board heard considerable evidence regarding the difficulty small producers are experiencing in obtaining gas sales contracts in the absence of new market opportunities. Because of the current oversupply of gas, traditional licence-holders have had little incentive to contract for additional supplies; hence, small producers, by and large, have been unable to find outlets for their shut-in reserves. The Board recognizes the need for these producers to have access to new markets to help alleviate their cash flow problems.

4.2.3 Contractual Arrangements

Introduction

In its Phase 1 Decision, the Board advised parties that, in assessing applications for new licences, it would place considerable emphasis upon the existence of reasonable take-or-pay provisions in the underlying export/import contract, where such provisions were appropriate. It was the Board's view that this approach preserves the right of the contracting parties to conclude their business relationships freely, responding as necessary to unique circumstances which might change over time. This as well as other elements of sound contract design are discussed below.

Contract Design

For the most part, Applicants were agreed that gas export contracts should include high load factor terms,[1] adequate take-or-pay (usually considered to be 75 percent of annual contract quantity), and a price for prepaid gas which was not less than the domestic price plus transportation. ProGas and Dome argued that prepaid gas should be paid for at the official export price and that monies collected under take-or-pay should not be refunded at the end of the contract. Other Applicants, notably KannGaz, countered that repayment clauses were fairly standard in gas contracts and that the amount of repayment, in its case, excluded the exporter's fixed costs of having made the gas available.

Consolidated and Niagara Gas argued that firm take-or-pay conditions should only be required where appropriate according to the characteristics of the market being served. Consolidated cited the evidence of its customer, Northern Natural, which stated that takes of gas under its contract would be at or about the minimum level in the early years, but would exceed the minimum level in later years as the need for supplemental supplies grew. The recent downturn in drilling in the United States, Consolidated argued, would make this even more likely. Niagara Gas emphasized the testimony of its customer, St. Lawrence Gas, that the company was fully dependent on Canada as its source of supply. If it were required to pay for gas not taken, its unit cost could increase to a level which would weaken its competitive position, particularly in its industrial market.

(1) The maximum daily volume in the contract should not greatly exceed the annual volume in the contract divided by 365.

Applicants were generally of the opinion that market-out[1] and regulatory-out[2] clauses (apart from those provisions requiring that contracting parties receive the necessary approvals in both countries) should be avoided where possible. TransCanada argued that the force majeure provision in virtually all contracts contained a form of regulatory-out clause in the wording of "circumstances beyond the control of the parties".

The Board believes that, in the ideal sense, there are desirable features which should be part of gas export contracts as well as undesirable features which should be avoided, if possible.

Desirable features would include high load factor terms, an adequate level of take-or-pay (seventy-five percent of annual contract quantity is considered to be adequate in most cases) with allowance for make-up in the year following expiry of the licence of gas paid for but not taken, and a price for gas paid for but not taken at the prevailing export price.

Undesirable features would include clauses which require the refund of take-or-pay monies at the termination of the sale[3] and clauses which potentially might relax the importer's obligation to take the contract quantity (e.g. market-out

(1) Market-out clauses, generally, relieve the buyer of its obligation to take the contract quantities of gas if the contract price exceeds the price at which the buyer can market the gas.

(2) Regulatory-out clauses could be any clause which relieve buyer or seller of any contract provision for reasons of regulatory constraint.

(3) Such clauses vary from contract to contract, but generally stipulate that if prepaid gas cannot be made up by the buyer through extension of contract term, removing maximum daily limits, etc., then some amount of take-or-pay monies must be repaid to buyer.

clauses, clauses linking take-or-pay in the export contract with take-or-pay in the producer contracts).

The Contracts As Filed

Generally, the contracts filed by the Applicants contain high load factor terms and adequate take-or-pay levels ranging between 65 and 100 percent. However, the Board finds that in many contracts the effect of the take-or-pay has been diluted by the inclusion of clauses which require the repayment of monies collected under take-or-pay at the termination of the sale. The KannGaz, Pan-Alberta, Sulpetro, Union Gas, Alberta and Southern, and Ocelot contracts contain such clauses. The Sulpetro clause, however, limits the repayment to monies collected in the last four years of the contract. In the case of Pan-Alberta, all of its transmission and other expenses would be deducted prior to refund of take-or-pay payments so that Pan-Alberta and its producers would be kept whole. Pan-Alberta argued that take-or-pay clauses should not be punitive since the United States importer must borrow the take-or-pay funds at considerable expense and the exporter has the use of the money. The TransCanada contracts also require repayment but only if government action prevents the make-up of prepaid gas during the contract period or a one-year extension thereto. With the exceptions of Dome, ProGas, Sulpetro and Union Gas, the price for take-or-pay gas is less than the official export price.

As well, two contracts contain clauses which could reduce the take-or-pay obligation of the importer. The Niagara Gas contract with TransCanada (the terms of which affect the export contract with St. Lawrence Gas) provides that take-or-pay only becomes effective when annual purchases exceed a certain level. Consolidated's contract with Northern Natural provides for the substitution of a lower take-or-pay level in the final three years of the contract. Both companies argued that a firm take-or-pay provision was not required given the characteristics of their markets.

The Board's concern with take-or-pay stems from the fact that the natural gas industry is a highly capital intensive, fixed investment industry. Markets tend to be concentrated in certain geographic areas away from the producing regions and are connected by large, dedicated pipeline systems to those regions. Take-or-pay has traditionally been the cornerstone upon which rests the financeability of pipeline projects. Without such provisions in sales contracts, many projects could not have been undertaken.

The Board, while generally satisfied with the quality of the contracts, agrees with Dome's comment that the difference in quality of the various contracts is indicative of the importer's confidence in its market. In the Board's view, the Dome and ProGas contracts with their high load factor and take-or-pay at the official export price with no refund provision most closely exemplify the ideals of sound contract design.

4.2.4 Pipeline Facilities

The applications to export natural gas involve the use of all major pipeline systems across Canada except those located in Quebec. The location of the transmission systems, existing and proposed, and points of export are illustrated in Figure 4-1.

The Board recognized that approval of certain applications to export gas will have a direct impact on the throughputs of existing pipeline systems and will, in the case of TransCanada, necessitate significant pipeline construction which would not otherwise occur.

The Board's review took into account the current capacity of the existing pipeline systems; forecast growth in the Canadian markets served by those pipelines, where applicable; projected facilities additions required to accommodate growth in these domestic markets; additional capacity required to transport the proposed new exports; cost of expanding and operating the additional facilities; fuel required to carry the new exports; impact on the cost of service; and netback to the producers.

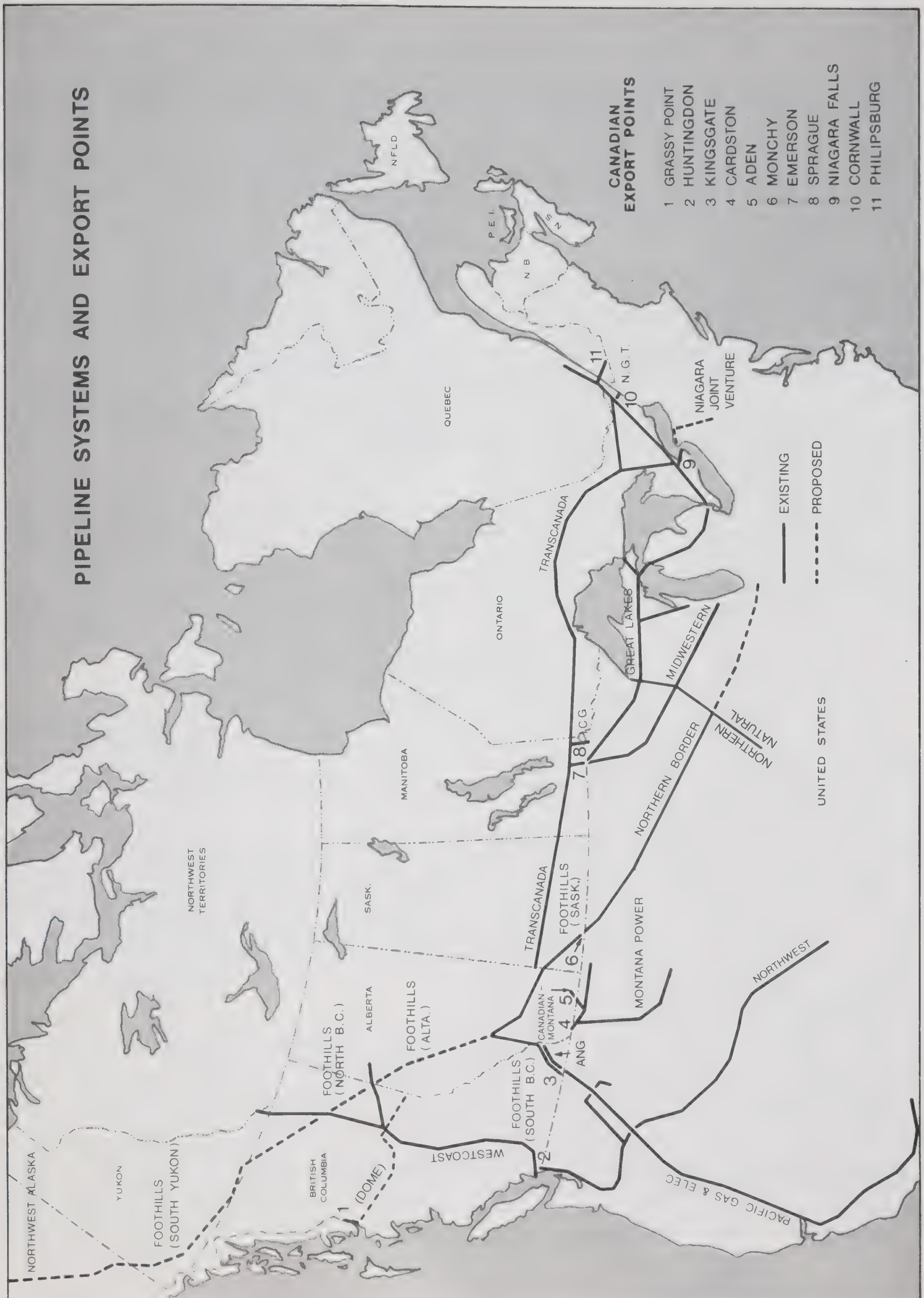
The Board notes that the applied-for exports by TransCanada, Niagara Gas, Canadian-Montana, Sulpetro, KannGaz, Pan-Alberta and ProGas, at the export points Emerson, Niagara Falls, and Cornwall, would require major expansion of TransCanada's Western and Central sections. TransCanada stated that the total incremental capital cost of expanding the system, to meet domestic and export requirements to the year 2000, would be 5.5 billion as spent dollars. This figure was based on TransCanada's line segment analysis and the following assumptions:

a) the level of Canadian transportation volumes via the Great Lakes system would remain constant at the 1982 level,

b) the Central section from Winnipeg to Toronto would be expanded to carry all new Niagara Falls exports and growing Eastern domestic requirements, and

c) domestic and export requirements as estimated by TransCanada.

Figure 4-1



PIPELINE SYSTEMS AND EXPORT POINTS
CANADIAN EXPORT POINTS
1 GRASSY POINT
2 HUNTINGDON
3 KINGSGATE
4 CARDSTON
5 ADEN
6 MONCHY
7 EMERSON
8 SPRAGUE
9 NIAGARA FALLS
10 CORNWALL
11 PHILIPSBURG
EXISTING
PROPOSED
NORTHWEST ALASKA
YUKON
FOOTHILLS (SOUTH YUKON)
NORTHWEST TERRITORIES
BRITISH COLUMBIA
(DOME)
WESTCOAST
FOOTHILLS (SOUTH B.C.)
FOOTHILLS (NORTH B.C.)
ALBERTA
FOOTHILLS (ALTA.)
CANADIAN - MONTANA
ANG
SASK.
FOOTHILLS (SASK.)
TRANSCANADA
MONTANA POWER
NORTHWEST
PACIFIC GAS & ELEC
MANITOBA
NORTHERN BORDER
NORTHERN NATURAL
UNITED STATES
ONTARIO
G.L.G.
MIDWESTERN
GREAT LAKES
TRANSCANADA
QUEBEC
NIAGARA JOINT VENTURE
N.G.T.
N.B.
P.E.I.
N.S.
NFLD

Utilizing the established current capacity and applying the annual growth increments determined by the Board in its forecast of natural gas demand in Canada, the Board determined the nature and extent of capacity additions required by this Decision. The Board further estimated the degree to which these facility additions would be utilized to serve future Canadian needs as exports declined and were terminated.

The Board based its analysis on the premise that future Canadian demands would be met by additional pipeline facilities constructed in Canada rather than by expanding the Great Lakes transmission system in the United States. The results of this analysis are presented in Figures 4-2 and 4-3.

The figures show the Board's estimate of the annual deliveries that will be made in each year from 1983 to 1999 through the Western and Central sections of the TransCanada system, under three scenarios: a base case reflecting Canadian requirements and currently authorized exports, an export case in which the new approved exports arising from the Board's Decision have been added to the base case (approved export case), and an export case in which all applied-for exports have been added to the base case (applied-for export case). All of the following analyses were made with respect to the approved export case.

The Board's analysis of current and future requirements for capacity on the TransCanada system shows that the maximum pipeline capacity in the Western section (Alberta border to Winnipeg) occurs in 1989. Surplus capacity develops beyond 1989 to the extent that the decline in authorized exports outpaces domestic market growth. The maximum surplus capacity, occurring in 1997, would be approximately 11.6 x $10^9 m^3$/year or 20 percent of Western section capacity. Surplus capacity declines beyond 1997 due to continuing domestic market growth. The surplus capacity could be minimized if some export volumes at Emerson were transferred to the Foothills prebuild Eastern Leg and exported at Monchy.

With respect to the Central section, the Board's analysis indicates that spare capacity exists during the period 1994-1999. The maximum surplus capacity, occurring in 1995, would be approximately 2.8 x $10^9 m^3$ per year or eight percent of Central section capacity.

Base Case: Includes Canadian requirements & currently authorized exports

Approved Exports: Base Case plus approved exports from Board's Decision.

Applied-for Exports: Base Case plus all applied-for exports.

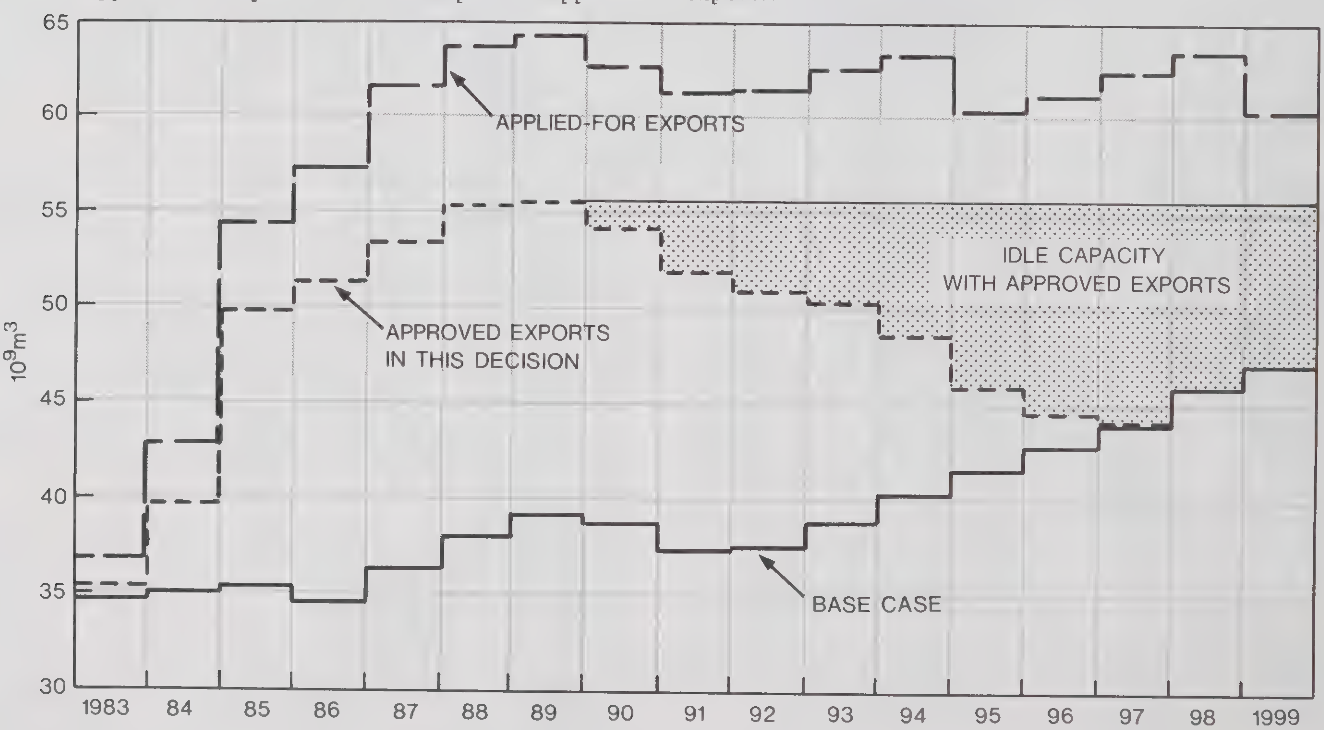


Figure 4-2 TransCanada PipeLines
Summary of Throughput Requirements
Western Section (Alberta Border to Winnipeg)
NEB Estimates

Base Case: Includes Canadian requirements & currently authorized exports
Approved Exports: Base Case plus approved exports from Board's Decision.
Applied-for Exports: Base Case plus all applied-for exports.

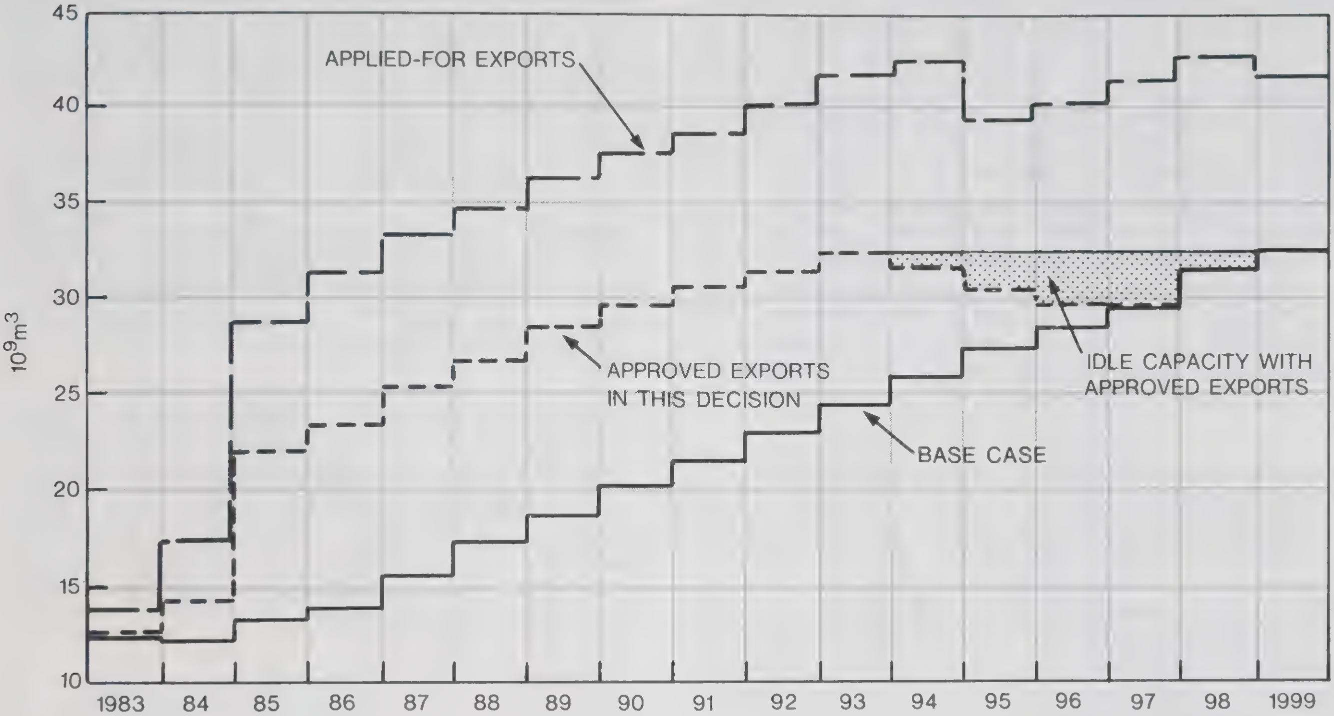


Figure 4-3 TransCanada PipeLines
Summary of Throughput Requirements
Central Section (Winnipeg to Toronto)
NEB Estimates

The Board has also assessed the impact of the approval of applied-for exports at Huntingdon, Kingsgate, Cardston, Aden, and Monchy on the transmission systems that would carry gas to be exported.

The Board is satisfied that only minimal additional pipeline facilities would be required to increase the capacity on the Westcoast, Alberta Natural, and Foothills (without Alaskan gas) pipeline systems to a level adequate to move the proposed new exports.

The Board notes Westcoast's proposal to construct an 880-kilometre express line to supply gas to the Dome LNG project. The system would be the first major east-west pipeline across British Columbia and according to Westcoast would be overdesigned to enable it to transport gas to potential petrochemical plants on the West Coast. The Board notes that the appropriateness of the design of this pipeline would be assessed in a Part III hearing. Further details on this proposal are provided in Section 4.2.6.

4.2.4.1 Producer Netbacks

In this section, submittors' views and Board views are summarized regarding the question of what significance producer netback price should be accorded in ranking the applications. Estimates of future tariffs on exporting pipeline systems are given and an example of one way in which producer netback prices can be estimated is included from which Board views are illustrated.

The Importance of Producer Netbacks

As noted above, the assessment of net benefits to Canada of various export proposals is best done through cost-benefit analysis. An assessment on this overall basis does not, however, reveal the distribution of the benefits which is, of course, of vital importance to producers, transmission companies, Applicants, and governments. The netback to the Alberta border out of which comes the producer netback and royalties and taxes paid to the Alberta and Federal governments (as well as gathering and transmission costs within Alberta) is of critical importance in determining whether a project can proceed and is among the important considerations taken into account by the Board.

There was considerable evidence presented at the Hearing regarding the importance of producer netbacks in determining which applications should be favoured. The APMC, in particular, took as its fundamental position that it wished to see cash flow to producers increased to the greatest extent possible through maximized netback from increased exports of natural gas. Alberta and Southern agreed that the bottom line is the netback to the producer and royalty owner. All submittors agreed that netback (price at the international boundary less transmission costs) was important, however, it was most common for submittors to consider netback as only one criterion of several and that it should not necessarily be predominant.

TransCanada argued that producer netbacks should not be over-emphasized. It was argued that under our present border pricing régime the revenue to Canada is the same whether the sale is made at Monchy, or Kingsgate, or Niagara Falls. TransCanada concluded that although a sale at Niagara Falls results in a lower producer netback, the substantial benefits accruing to the Canadian economy, including the substantial multiplier effects associated with the related construction, should not be disregarded.

IPAC indicated that early incremental revenues were more important than the level of netbacks. CPA was more interested in the level of returns to producers especially in relation to the Dome LNG application which it contended would not provide producers an assured minimum price.

Cost of Transmission

In order to assess the relative netbacks to the Alberta border from exports at various exit points the Board estimated applicable transportation tariffs. Given a uniform price at the international boundary, the Alberta border netback can be estimated by simply subtracting the cost of transmission from the Alberta border to the international boundary.

Applications were received for export of gas from Alberta which proposed exit points at Kingsgate, British Columbia on the ANG pipeline and on the Foothills pipeline (Prebuild Western Leg); at Cardston and Aden on the Alberta-Montana border; at Monchy, Saskatchewan on the Foothills pipeline (Prebuild Eastern Leg); at Emerson, Niagara Falls and Cornwall on TCPL; and at Grassy Point, British Columbia under the Dome LNG proposal. The cost of transmission for Alberta gas for exit points other than Grassy Point are shown in 1981 Canadian dollars in Table 4-9. The Dome netback for LNG sold to Japan is discussed in Section 4.2.5.

In the case of exports at Aden and Cardston transportation costs are incurred only within Alberta, so no tariff is shown. In the case of the Foothills pipeline (West and East) the numbers shown represent only the cost of transportation outside Alberta.

In the case of TCPL a more detailed procedure was necessary to estimate tariffs because new facilities will be required for both domestic deliveries and new export shipments. Evidence regarding the cost of expanding TCPL's system which was submitted by TCPL was added to the current rate base to estimate a rolled-in or average cost of transmission.

Construction cost data submitted at the hearing were used along with assumptions for depreciation, rate of return, etc., in order to estimate the incremental cost of transmission for proposed exports via TCPL. Throughput assumptions correspond to the Decision described in Chapter 5 at a 100 percent load factor, and the Board's domestic demand forecast.

Ontario and Consumers' Gas commented that domestic shippers should not be obliged to pay additional costs associated with facilities built for exports. Whether a rolled-in or an incremental approach is appropriate may be considered at Parts III and IV hearings that may follow this export licensing decision. For illustrative purposes both rolled-in and incremental tariffs are shown on Table 4-9 for TCPL export shipments.

Netbacks

The Board's illustrative estimates of the Alberta border netback under alternative world oil price assumptions are shown in Table 4-10 in 1981 Canadian dollars. The Canada-United States border prices shown correspond to the Base Case and the Alternative Case world crude oil price scenarios used in the estimation of gas demand. For the purposes of this illustration the international border price for gas has been assumed to become 70 percent of the United States refiner aquisition cost for crude oil. For this illustration the Board has chosen prices that are assumed to be uniform for all border points (except for Dome). The Board recognizes, however, that as the United States progressively moves toward decontrol of gas prices, there will continue to be pressures in the future which may give rise to a re-evaluation of not only the absolute level of export prices but also the continued appropriateness of a border price that is uniform all the way from Huntingdon in Southwest British Columbia to Phillipsburg in Quebec.

Table 4-9
ESTIMATED COST OF TRANSMISSION(1)
Canadian $/GJ (1981)

	1984	1987	1990	1993
Alberta Border-Kingsgate				
ANG(2)	.07	.07	.07	.07
Foothills(2)	.18	.14	.12	.10
Alberta Border-Monchy				
Foothills(2)	.15	.15	.12	.10
Alberta Border-Emerson, TCPL				
Incremental (3)	.45	.35	.30	.36
Rolled-in (4)	.30	.26	.27	.28
Alberta Border-Niagara Falls, TCPL				
Incremental (3)	2.53	1.97	1.46	1.08
Rolled-in(4)	.92	.81	.84	.87

(1) Cost of transmission has been projected on the assumption that present rate-making procedures will continue.

(2) For ANG and Foothills it was assumed that no new facilities would be required after 1983 and that throughputs would continue at current levels. It was also assumed that Foothills "basket provisions" which provide for accelerated depreciation in the event that Alaska gas does not flow would not be invoked.

(3) Cost of transmission estimated assuming export-related facilities stand alone with 12-year amortization.

(4) Cost of transmission estimated assuming full "roll-in" of export facilities and normal depreciation rates.

Table 4-10

ALBERTA BORDER NETBACK FROM EXPORT SALES (Illustrative)
Canadian $/GJ (1981)

Assuming a constant real price for imported oil:

	1984	1987	1990	1993	1999
U.S. Border Price	4.46	4.68	4.90	4.97	4.96
Alberta Border Netback					
-Aden/Cardson	4.46	4.86	4.90	4.97	
-Kingsgate, ANG	4.39	4.61	4.83	4.90	
-Kingsgate, Foothills	4.28	4.54	4.78	4.87	
-Monchy, Foothills	4.31	4.53	4.78	4.87	
-Emerson Inc.(1) TCPL	4.01	4.33	4.60	4.61	
-Emerson Rolled-in(2) TCPL	4.16	4.42	4.63	4.69	
-Niagara Falls Inc. (1) TCPL	1.93	2.71	3.44	3.89	
-Niagara Falls Rolled-in(2) TCPL	3.54	3.87	4.06	4.10	
-Dome(3)	-	2.11	1.96	2.79	4.11
-Dome(4)	-	2.65	2.17	2.59	3.94
-Domestic Sales	2.20	2.56	2.71	2.78	2.72

Assuming a 20% decline in the real price for imported oil by 1985 and constant thereafter:

	1984	1987	1990	1993	1999
U.S. Border Price	4.20	3.86	4.04	4.10	4.09
Alberta Border Netback					
-Aden/Cardston	4.20	3.86	4.04	4.10	
-Kingsgate, ANG	4.13	3.79	3.97	4.03	
-Kingsgate, Foothills	4.02	3.72	3.92	4.00	
-Monchy, Foothills	4.05	3.71	3.92	4.00	
-Emerson Inc.(1) TCPL	3.75	3.51	3.74	3.74	
-Emerson Rolled-in(2) TCPL	3.90	3.60	3.77	3.82	
-Niagara Falls Inc.(1) TCPL	1.67	1.89	2.58	3.02	
-Niagara Falls Rolled-in(2) TCPL	3.28	3.05	3.20	3.23	
-Dome(3)	-	1.21	1.04	1.88	3.20
-Dome(4)	-	1.76	1.26	1.68	3.03
-Domestic Sales	2.20	2.52	2.58	2.55	2.40

(1) Cost of transmission estimated assuming 12-year depreciation of export facilities.

(2) Cost of transmission estimated assuming full roll-in of export facilities and normal depreciation rates.

(3) Cost of service calculated assuming 15-year amortization and based on Dome's capital cost estimates as filed.

(4) Same as (3). but with 20-year amortization.

Notwithstanding the uncertainty of future gas prices, the Board feels that some important conclusions can be reached from this assessment of netbacks. It is evident, as expected, that on an incremental basis exports at Niagara Falls via TCPL and export to Japan (discussed in detail in Section 4.2.5) will generate, at least in early years, lower netbacks than exports from Western Canadian exit points. It is also possible that netbacks from these sales may be lower at certain periods of time than those forecast for domestic sales. It is also evident, again not unexpectedly, that exports at Kingsgate, Aden/Cardston, Monchy and Emerson all yield satisfactory netbacks.

4.2.5 Western LNG Project

4.2.5.1 Japanese Markets

Overall Demand for LNG

Dome presented evidence that indicated Japan would require an increasing supply of LNG to meet growing energy demands. LNG requirements are expected to increase from some 900 PJ (16.8 million tonnes) in 1980 to some 2 100 PJ (38.5 million tonnes) by 1990 and to some 2 500 PJ (45 million tonnes) by 2000. In percentage terms, natural gas, of which 90 percent is derived from imported LNG, is expected to raise its market share of total Japanese energy demand from six percent in 1980 to 11.5 percent by 1990. Dome stated that this strong growth was predicated on the assumptions that:

- the Japanese economy would continue to perform strongly and the demand for thermal electric generation capacity would continue to grow,
- long-term Japanese energy policy would continue to support the general shift away from imported crude oil to natural gas and other alternatives, and
- nuclear power, the chief competitor to increased consumption of LNG in Japan, would continue to be constrained by the long lead times required for the approval and construction of nuclear plants.

Japanese Buyers

The buyers of the Western LNG Project gas would be five Japanese utility companies: the Chubu Electric Power Co. Inc., purchaser of 56 percent of the gas; Osaka Gas Company, Ltd., (19 percent); Kyushu Electric Power Co., Inc., (ten percent); the Chugoku Electric Power Co., Inc., (ten percent); and Toho Gas Company Ltd., (five percent). These companies are considered to be among the largest and most respected utility companies in Japan, and all, with the exception of Chugoku, currently purchase and use imported LNG in their systems. By 1990, the Western LNG Project would provide between 10 and 25 percent of each purchaser's LNG imports.

Price

The application by Dome envisions approval by the Board of an export price determined in accordance with the terms and conditions of the gas export contract between Dome and NIC Resources, and the five Japanese buyers. The contract selling price, which is C.I.F.[1] Japan and calculated on each cargo at the time of completion of unloading, starts with a base price in 1981 of United States \$6.585 per MMBtu (United States \$6.242 per GJ) and varies according to the following formula:

Contract Sales Price = \$6.585 x (0.5 x A/A' + 0.5 x B/B')

where:

A = The Canada-United States Border Reference Price in effect at the time of LNG unloading completion in Japan.

A' = United States \$4.94/MMBtu, the Canada-United States Border Reference Price in effect on 26 August 1981.

B = The arithmetic average of the official government sales prices (excluding premiums, discounts and spot sales) F.O.B. per barrel in United States dollars for contract sales of the following crude oils at the time of LNG unloading completion in Japan:

Arabian Light 34°
Sumatran Light 34°

B' = United States \$33.50 per barrel representing the arithmetic average of the official government sales price (excluding premiums, discounts and spot sales) F.O.B. for contract sales of the above crude oils in effect on 26 August 1981, subject to retroactive adjustment, if any.

(1) C.I.F.: cost, insurance and freight charges are paid by the seller.

Based on an assumption of an annual increase of two percent in real energy prices and on its forecast of inflation, Dome estimated the C.I.F. price, over the life of the project, as set out in Table 4-11.

Table 4-11

DOME ESTIMATE OF C.I.F. PRICE[1]
(Current U.S. $/GJ)

Year	CIF Price
1986	9.11
1990	13.39
1995	21.69
2000	35.08
2005	56.66

Dome also presented evidence which indicated that the price for LNG under the formula in its contract would have been as high as or higher than prices paid for other LNG imports into Japan in 1981.

4.2.5.2 Contractual Arrangements

In support of its application, Dome provided evidence on the status of contractual arrangements related to the Western LNG Project.

LNG C.I.F. Sales Agreement

The LNG C.I.F. Sales Agreement, dated 20 March 1982, sets out the relationship between a joint venture consisting of Dome and NIC Resources, as seller, and the five Japanese utility companies, as buyers, of Western LNG Project gas at the receiving terminal in Japan. It stipulates the sales volumes, the 20-year term and the C.I.F. sales price which underpin the export proposal. As well the contract contains a 100 percent take-or-pay provision against the annual contract quantity for each buyer. One of the more significant concerns expressed during the Hearing was the broad phrasing of the "force majeure" provision which appeared to include government intervention as an element which could interrupt the contract. An additional concern related to those conditions in the Sales Agreement which required that certain approvals from governments in Canada and Japan be obtained before the Sales Agreement itself could become effective.

(1) Based on Dome's assumption of an annual increase of two percent in real energy prices. This assumption formed the basis for Dome's Base Case.

The conditions to be met in Canada included receipt of the following:

- a removal permit from Alberta,
- a removal permit and certificate from the Government of British Columbia,
- a certificate for the pipeline and the marine terminal from the Government of British Columbia,
- a gas export licence and certificates of public convenience and necessity for the pipeline and the marine terminal from the NEB, and
- TERMPOL Code approval for the marine terminal.

F.O.B. Sales Agreement

The F.O.B. Sales Agreement dated 24 September 1982, sets out the relationship between Dome as owner of the gas and the Dome and NIC Resources joint venture as buyer of the gas at the outlet of the LNG plant in Canada. It contains terms and conditions with respect to take-or-pay and force majeure which are virtually identical to those found in the LNG C.I.F. Sales Agreement. Sales volumes for the F.O.B. Agreement are derived from those contained in the C.I.F. Sales Agreement. The F.O.B. Sales Agreement also defines the contract sales price at the plant outlet as being the C.I.F. price less the cost of marine transportation, marine cargo insurance and management/administration charges.

LNG Processing Agreement

The LNG Processing Agreement, dated 4 October 1982, sets out the relationship between Dome as owner of the gas and the Western LNG Plant Partnership (Dome 90 percent, NIC Resources ten percent), as owner of the LNG Plant. It sets forth the conditions under which the natural gas is processed into LNG and stored at the plant site and establishes the basis for the determination of the monthly cost of service charge which the Partnership will recover from Dome.

Marine Transportation Agreement

The Marine Transportation Agreement, dated 4 October 1982, sets out the relationship between Dome and NIC Resources as shipper and Dome and NICR Shipping Co. Ltd. as transporter. It sets forth the terms and conditions under which the transporter will arrange for time charters on five LNG vessels to transport volumes to be sold pursuant to the LNG C.I.F. Sales Agreement and the F.O.B. Sales Agreement. It also defines the

allowable costs that the transporter may charge the shipper.

Gas Purchase Contracts

The Western LNG Project is based on 75 percent of the gas being supplied by Alberta and 25 percent by British Columbia. Regarding the Alberta sourced gas, Dome filed a gas purchase contract, dated 24 September 1982, between TCPL as seller and Dome as buyer. Dome indicated that a removal permit with respect to the removal of the required gas from Alberta had not been issued by the Province by the close of the Hearing. Regarding the British Columbia sourced gas, Dome stated that while the project had received approval in principle from the Government of British Columbia through the Natural Gas Allocation Process, a detailed supply agreement was not in place. Dome stated that meetings with officials of both provincial governments to resolve these outstanding matters were expected to take place in the near future. Dome undertook to file the removal permits with the Board when they were issued by the Governments of Alberta and British Columbia.

Gas Transportation Contract

Dome filed a memorandum of understanding between Dome and Westcoast governing the transportation of Dome's gas from the Alberta border to the LNG Plant. Dome expected a fully executed agreement to be available before the end of 1982 and undertook to file a copy with the Board. At year-end 1982 the Board had not received this document.

4.2.5.3 Facilities, Estimated Costs and Financing Arrangements

Marine Transportation

A transportation company, Dome-NICR Shipping Co. Ltd., has been formed for the purpose of providing five LNG vessels to the Western LNG Project. These vessels will transport the LNG from the liquefaction plant in British Columbia to the receiving terminals of the utility companies in Japan pursuant to the Transportation Agreement described above. The vessel availability schedule was forecast to be as follows:

Vessel Number	Date
1	11 March 1986
2	10 May 1986
3	27 July 1986
4	31 August 1987
5	15 August 1990

Dome provided marine transportation cost estimates for two cases: the first assumed the use of three existing vessels and two new vessels to be built specifically for the Project; the second assumed all five vessels were newly built. Dome concluded that the cost of using newly built LNG vessels would be relatively the same as that of using existing vessels. Dome pointed out that the lower purchase price of existing carriers, United States $57 million compared to United States $160 million for new vessels, would be largely offset by higher operating costs and by the high lay-up costs incurred prior to the project start-up date.

Dome suggested that another important consideration is that while most ships have a useful life of 20-25 years, it is desirable for new LNG trade to use ships with 20-year remaining lives available. This makes it difficult to charter existing ships with sufficient useful life.

It was Dome's position that the possibility of overruns on either capital costs or annual operating costs was minimal. Dome indicated that it had not yet taken a final decision on whether to acquire existing or newly built vessels. It was satisfied that, in any event, the final costs of acquiring the vessels would not exceed those included in the application. CPA expressed the concern that because the time charter had not been finalized, there existed a possibility that further escalation in operating costs could occur.

On the question of financing, Dome stated that it assumed that financing from the United States Maritime Administration would be available for existing vessels. This financing would have a rate of interest of 8.5 percent over a 21-year term but would be available only for United States-owned ships using United States crews. Although financing had yet to be negotiated for new vessels, Dome estimated that attractive interest rates would be available from Japan or Europe, depending upon where the vessels were to be constructed.

LNG Plant and Storage Facilities

Dome indicated that the Western LNG Project liquefaction plant and storage facilities would be located immediately south of Grassy Point on Port Simpson Bay, British Columbia. The site is about 28 kilometres northwest of Prince Rupert. The facilities would consist of:

- the gas pre-treatment and liquefaction process equipment using the Air Products design process;

- four storage tanks fabricated from stainless steel with nine percent nickel content, each with a storage capacity of 79,500 cubic metres;

- the LNG carrier berthing wharf and loading system; and

- utility systems and other ancillary systems and equipment.

The facilities would be designed to liquefy 13.6 million cubic metres per day of natural gas by means of two 6.8 million cubic metre process trains. Assuming full production for 326.5 days per year the annual volumes of natural gas processed would amount to 4.4 billion cubic metres.

Dome estimated the cost of the LNG plant and storage facilities to be $1.17 billion in 1981 constant Canadian dollars. It believed the accuracy of this estimate to be plus or minus 25 percent. Dome believed the risk of cost overrun on the plant and storage facilities would be minimal and presented a risk analysis in support of this view. The results of the risk analysis, done by means of a Monte Carlo simulation, indicated the expected cost of the plant would be 74.3 percent of the filed estimate, or $870 million, with a 95 percent chance that the plant would cost between $716 million and $1.024 billion (in 1981 constant dollars). In its analysis of the Project, the Board used the filed capital costs rather than the risk-adjusted costs, because of concern regarding the assumptions and methodology employed in Dome's risk analysis.

Dome indicated that financing in the amount of United States $1,966.5 million (as spent dollars) would be obtained for the Western LNG Project liquefaction plant and storage facilities through the Japanese institutional financing program. This amount would include $15.5 million for tug boats, $1,578.1 million for the plant, and $222.9 million for the interest during construction and a portion of the working capital (in as-spent United States dollars).

The interest rate on the loan is estimated to be 9.75 percent comprised of a base rate of 9.25 percent plus 0.5 percent, a component related to financing costs in Japan. The interest on the outstanding balance is to be paid each quarter after the construction is complete and shipment has begun. The principal is to be repaid over ten years following plant start-up in equal quarterly amounts but subject to reduction during the volume build-up period. The security provided to the Japanese lender would consist of an assignment of revenues arising from the Sales Agreement, a mortgage on the plant facilities, completion undertakings, and ultimate responsibility of the Project Sponsors to retire the loan in full.

In the LNG Processing Agreement, Dome has proposed a cost of service for the LNG plant and storage facilities which reflects a deemed capital structure over the 20-year project life consisting of 65 percent debt and 35 percent equity. In addition, the estimated cost of service reflects the following features:

- costs of debt of 9.75 percent and 13 percent: 9.75 percent applicable to the Japanese loan and 13 percent applicable to the difference between the amount of the Japanese loan outstanding and the debt portion of the deemed capital structure,

- return on equity of 20 percent along with deferral and recapitalization of some equity returns in early years,

- AFUDC at a composite rate based on the costs of debt and equity,

- normalized income taxes, and

- depreciation deferred in the early years, with partial depreciation taken in the fourth and fifth years of operation, and full depreciation taken over the remaining life.

Dome stated that the Partners have concluded that the deemed financing and other cost of service assumptions would generate amounts of cash sufficient to compensate them for the risks to which they perceive themselves to be exposed in the Project. Dome asserted that this revenue stream or one substantially similar would be necessary for it and its partners to commit to proceed with the Project.

The Board has estimated that based on revenues earned during the life of the project and taking into account operating and maintenance charges and interest on and repayment of the Japanese loan, the cash flow (before taxes) accruing to the Partners over the project life associated with Dome's applied for 20-year export licence would be some $4.5 billion (current Canadian dollars). This assumes no capital cost overruns and, therefore, no or only a very small initial equity investment by the Partners.

Natural Gas Pipeline

Dome indicated that the natural gas from Alberta required as feedstock for the Western LNG Project would be transported from the Alberta border to the plant at Grassy Point in a pipeline to

be constructed, owned, and operated by Westcoast. Westcoast expected the line would be some 880 km long and would be a 660mm O.D. express line. Initially four mainline compressor stations and one injection station at Willow Flats to handle British Columbia gas would provide peak day capacity of 14.96 million cubic metres per day. By adding four additional stations, peak day capacity could be increased to 19.4 million cubic metres per day.

The cost of the pipeline from the Alberta border as far as Prince Rupert was estimated by Dome to be $529 million in 1981 constant dollars. The estimate was based on Westcoast experience and took into account recent large increases in labour, land and material costs. Dome considered it to be accurate within a range of plus or minus 15 percent. Dome presented a risk analysis in support of its view that the risk of cost overrun on the pipeline would be minimal. The results of the risk analysis, similar to that performed for the liquefaction plant and storage facilities, indicated the expected cost of the pipeline would be 77.2 percent of the filed estimate, or $408 million, with a 95 percent chance that the pipeline would cost between $324 million and $492 million (in 1981 constant dollars). In its analysis of the Project the Board used the pipeline costs as filed.

Westcoast indicated that financing arrangements for the natural gas pipeline are expected to be conventional. It expected that this subject matter will be dealt with in detail at subsequent Part III and Part IV hearings. Although Dome had included in its application a pro forma pipeline cost of service for the proposed Westcoast pipeline which reflected the same tariff assumptions that were made for the LNG plant, Westcoast was unwilling to accept these assumptions until it was clear what risks the pipeline would be expected to bear and whether financing arrangements could be struck which were satisfactory to both Westcoast and its lenders.

4.2.5.4 Economic Viability

Introduction

The objective of economic viability analysis is to determine whether or not the project's revenues will be sufficient to provide an adequate return to the project participants. If the revenues are not sufficient, the project may not be able to proceed on schedule without a direct or indirect subsidy.

Under Dome's proposal, project revenues will be distributed as follows to cover project costs:

(i) the marine transportation costs from the LNG plant to Japan;

(ii) the management fee to Dome and NIC Resources;

(iii) the cost of liquefaction of the gas;

(iv) the cost of transporting feedstock natural gas through a trans-British Columbia pipeline; and

(v) as a residual after the above charges have been paid, the purchase cost of the natural gas.

To be considered viable, the project revenues must be able to cover all of the above five cost items. Since four of the five cost charges are determined by a formula, only the purchase cost of the gas will be a variable. Dome's viability calculations, therefore, focussed on the Project netback at the Alberta border. For purposes of its netback calculations Dome assumed all the gas for the Project would be sourced in Alberta. (The Project, in fact, contemplates that only 75 percent of the gas will be supplied from Alberta with the remaining 25 percent being supplied by British Columbia. To this extent, the Dome calculations of netback approximate the expected netbacks.)

Economic viability is an analysis of minimum sufficiency for each party affected by the Project. In this regard, it differs significantly from an assessment of the Project's ranking relative to the other export proposals in the Hearing. It is the Board's view that project ranking is better addressed by benefit-cost analysis which uses a total society perspective to compare alternatives and identifies which proposal is most attractive from the standpoint of the national interest.

Calculation of Project Netback

The Western LNG Project will charge a C.I.F. price for its gas deliveries to Japan that is based on the formula contained in the LNG C.I.F. Sales Agreement.

Exports from Canada will receive F.O.B. revenues, derived by subtracting from the C.I.F. revenues the costs of marine tanker charter and a management fee of 2.5 percent of the F.O.B. revenues. Dome proposed that the liquefaction plant and the pipeline facilities both be on a cost-of-service basis. The residual becomes the revenue at the Alberta border to be apportioned between the producers, NOVA service charges, and taxes and royalties.

Dome provided a comparison of its annual netbacks to the Alberta border with its own forecast of the Alberta border price (for domestic sales), under assumptions of -2 percent, 0 percent and +2 percent annual changes in the real price of world oil. The Canada - United States border price for natural gas was assumed to equal 85 percent of the Duncan-Lalonde formula throughout the period of analysis.

To obtain a forecast of the Alberta border price, Dome made forecasts of the average Canadian blended oil price and of the average TCPL tariff from Alberta to Toronto. The Alberta border price was then calculated by defining the Toronto city gate price as 65 percent of the average Canadian blended oil price and then subtracting the average TCPL tariff between Alberta and Toronto. Dome's estimates of Alberta border prices and project netbacks under its three assumptions with respect to changes in the real price of world oil are shown in Table 4-12.

The case which assumes an annual two percent increase in real world oil prices shows a very healthy margin for Dome's netbacks over the annual Alberta border price for domestic sales. Dome considered this to be its base case. The other cases indicate the sensitivity of the results to the assumed level of world oil prices. They indicate that the netback from Western LNG Project sales could be below the Alberta Border price for domestic natural gas sales until the 1990's.

In order to assess the viability of the Western LNG Project, based upon evidence relating to project life and capital costs, C.I.F. prices, project costs of service, domestic natural gas prices and domestic pipeline tariffs, the Board prepared its own analysis under a variety of assumptions. The results generally indicated that under the fiscal arrangements proposed by Dome the netbacks from Western LNG Project sales could be below the Board's forecast of the Alberta border price from project start-up until at least the mid-1990's and thereafter might exceed the Alberta border price by an increasing margin. This suggests that what may be required is some form of redistribution over time of the Project revenues between the Sponsors and the gas producers and the provincial governments. In this regard the Board notes that the before-tax return to the Partners, estimated to exceed $4.5 billion over the Project life, may be unduly high, particularly in view of the fact that, if the plant is built within the amount estimated by Dome, the equity investment required of the Partners will be insignificant.

These estimates of netback are most sensitive to changes in energy prices. Potential cost overruns of 20 to 40 percent would also have significant impact on project economics, although this impact would be less than that caused by energy price changes.

Who Bears the Risk?

Dome argued that based on an expected two percent annual increase in the real price of world oil, and taking into account the value of its high load factor, expected to be at or close to 100 percent, there would be an adequate return to producers. According to Dome, the plant and the pipeline are "utility conduits" for the export sale and should be treated on a cost-of-service basis. Consequently, according to Dome, the producers of the gas should bear the risks associated with possibilities such as capital cost overruns on the plant or pipeline, or low energy prices. Counterbalancing these risks were the up-side benefits the producers would receive if energy prices were to escalate rapidly, or if the plant or pipeline came in under budget as indicated by the risk analysis filed by Dome.

The project as proposed by Dome means that producers must bear four basic types of risk:

(i) reductions in netbacks resulting from lower than expected energy prices;

(ii) reduction or interruption of shipments to Japan;

(iii) reductions in netbacks arising from marine transportation costs being higher than expected;

(iv) reductions in netbacks arising from cost overruns on construction which would increase the cost of service of the liquefaction facilities and/or the pipeline.

During the Hearing, a number of participants expressed views on the topic of minimum netbacks and the risk to producers associated with Dome's LNG proposal.

ProGas reflected a concern that the project would not generate a sufficient return to producers. The CPA expressed a strong opposition to the Dome project, arguing that there was insufficient information on the record to attempt a realistic evaluation of the risks which the producers would have to bear. Opposition to Dome because of uncertainty over netbacks and lack of protection against cost overruns was also expressed by Norcen.

Table 4-12

Dome Estimates of Alberta

Border Prices and Project Netbacks

($/GJ)

	Assuming 2% Annual Real Reduction In World Oil Prices			Assuming Constant Real World Oil Prices			Assuming 2% Annual Real Increase In World Oil Prices		
Year	Domestic Netback (1) (i)	LNG Netback (2) (ii)	Difference (ii)-(i)	Domestic Netback (1) (iii)	LNG Netback (2) (iv)	Difference (iv)-(iii)	Domestic Netback (1) (v)	LNG Netback (2) (vi)	Difference (vi)-(v)
1986	3.56	4.45	0.89	3.60	4.85	1.25	3.98	5.51	1.53
1987	3.47	3.89	0.42	3.94	4.70	0.76	4.45	5.60	1.15
1988	3.71	3.80	0.09	4.32	4.85	0.53	4.98	6.00	1.02
1989	3.98	3.56	(0.42)	4.69	4.94	0.25	5.53	6.49	0.96
1990	4.30	3.48	(0.82)	5.11	5.16	0.05	6.16	7.06	0.90
1991	4.52	3.16	(1.36)	5.63	5.14	(0.49)	6.92	7.51	0.59
1992	4.88	3.74	(1.14)	6.20	6.14	(0.06)	7.78	8.98	1.20
1993	5.26	4.51	(0.75)	6.82	7.33	0.51	8.71	10.73	2.02
1994	5.64	5.33	(0.31)	7.49	8.66	1.17	9.76	12.67	2.91
1995	6.07	6.21	0.14	8.21	10.02	1.81	10.89	14.79	3.90
1996	6.50	7.13	0.63	8.98	11.53	2.55	12.13	17.13	5.00
1997	6.97	7.92	0.95	9.82	12.97	3.15	13.51	19.51	6.00
1998	7.49	9.03	1.54	10.77	14.80	4.03	15.18	22.41	7.23
1999	8.02	10.16	2.14	11.75	16.71	4.96	16.77	25.52	8.75
2000	8.60	11.78	3.18	12.83	18.71	5.88	18.64	28.89	10.25
2001	9.21	12.38	3.17	14.01	20.77	6.76	20.71	32.49	11.78
2002	9.86	13.56	3.70	15.29	23.01	7.72	23.01	36.47	13.46
2003	10.56	14.83	4.27	16.68	25.47	8.79	25.52	40.87	15.35
2004	11.27	16.07	4.80	18.12	28.00	9.88	28.23	45.60	17.37
2005	12.06	17.21	5.15	19.76	30.56	10.80	31.31	50.60	19.29

(1) Alberta Border Price for Domestic Sales
(2) Netback from Western LNG Project Sales

The APMC expressed qualified support for the LNG project, conditioning its support on netbacks to the Alberta producers being comparable to the netbacks received from exports to the United States. British Columbia expressed strong support for the project and voiced its belief that the condition of support stated by the APMC could be met.

As mentioned earlier, economic viability analysis attempts to determine, from a private sector point of view, whether Project revenues are sufficient to provide an adequate return to participants. In essence whether the Project is viable from the perspective of all participants, including the Sponsors, Westcoast, gas producers and provincial governments, and whether the risks are shared equitably by the parties is really a matter for those parties to decide. Complete information was not available on this issue when the Hearing closed. The matter is further discussed in Section 4.3.4.

4.2.5.5 Canadian Content, Other Economic Impacts

Canadian Content

In developing the Western LNG Project, Dome stated that one of its main objectives is to maximize Canadian benefits, particularly in the area of industrial capability. Dome also stated that the development of LNG technology would be a non-quantifiable benefit of the Project.

Dome estimated the Canadian content of the LNG Plant would be 81 percent. The major items of non-Canadian content were specialized equipment that is not manufactured in Canada. Dome indicated that the extent of the transfer of the Air Products process technology, which had been selected for the LNG Plant, from the United States parent to a Canadian subsidiary was subject to further negotiation.

Dome indicated it was still pursuing a Canadian content target of 50 percent with respect to the LNG vessels. If the decision were made to construct new LNG vessels, Dome stated it had been advised by both Japanese and European shipyards that a Canadian content of ten percent of the ship's value could be easily attained without materially affecting the cost of the ship. A higher percentage than that would have to be looked at based upon availability and economic considerations. Dome stated that, in conjunction with personnel from the Federal Department of Industry, Trade and Commerce/Regional Economic Expansion, it was looking at other competitive Canadian goods as part of an offset package with a foreign shipyard. It was stated that the final results would depend on the capability of Canadian industry to sell in world markets. During cross-examination Dome agreed that there was very little hard evidence to substantiate the claim that the 50 percent Canadian content level for the LNG vessels would be achieved. Dome's estimate that the Canadian content of the natural gas pipeline would be 91 percent was not seriously contested.

Economic Impact

Dome employed multiplier analysis techniques which indicated that the construction phase of the project would directly and indirectly generate about \$1.83 billion in revenues throughout the economy and create some 44,000 person-years of employment. The operation phase was estimated by Dome to generate some \$928 million in revenues and some 25,000 person-years of employment spread over the life of the Project.

Regional Socio-Economic Impact

Dome stated that its policy is to work with groups affected by the Western LNG Project and with the appropriate levels of government to minimize negative regional socio-economic impacts and maximize economic benefits to the region. Detailed studies would be filed in a subsequent facilities application.

The Port Simpson Indian Band indicated that, in light of current negotiations with the Applicant whereby various benefits would flow to the Band and certain concerns of the Band would be addressed, it did not wish to oppose the application for a licence to export natural gas.

4.2.6 Cost-Benefit Analysis Summary

4.2.6.1 Introduction

Before granting new licences to export natural gas, the Board determines inter alia that such exports are in the public interest. Among considerations the Board takes into account is whether such new exports will be of overall economic benefit to Canadians.

One means of assisting in the evaluation of the net benefits to Canada from the export of natural gas is to assess proposed exports within the framework of a cost-benefit analysis. An advantage of using this form of analysis is that the Board can assess the direct benefits and costs resulting from the export sale against the alternative of keeping the natural gas in Canada and using it to meet Canadian requirements in some future period.

The Board, therefore, required each Applicant to submit a cost-benefit study showing the estimated benefits to Canada from exporting the requested quantity of natural gas. The guidelines issued to Applicants by the Board are contained in Appendix VII.

Each Applicant submitted a cost-benefit analysis showing the estimated benefits to Canada from the exports it was applying for. Because of differences in assumptions and methodology the resulting estimates were not directly comparable.

A&S submitted a cost-benefit analysis of each of the export proposals on a stand-alone basis (i.e. assuming no other exports would be approved). A&S generally attempted to utilize standardized assumptions for all export proposals, although in doing this it made its own estimates from filed evidence in regard, for example, to export term and volumes, and producer and NOVA capital and operating costs.

Other Applicants and Intervenors raised objections to several A&S assumptions, particularly those regarding the timing of exports, transmission capital costs, and user cost (which measures the increased cost to Canadians in the future, as higher cost sources of natural gas are produced at an earlier date, because of gas exports). In particular, it was argued that the A&S estimate of user cost was too high because its approach involved serious double counting. Essentially this double counting arose from an error in methodology whereby the A&S estimate of user cost incorrectly included costs which would be incurred with or without exports.

Having reviewed all the analyses placed before it, the Board undertook its own cost-benefit analyses in order to measure the various export proposals from a common basis and in order to be able to evaluate the sensitivity of the results to alternative assumptions.

4.2.6.2 Purpose of the Board's Cost-Benefit Analyses

The Board's cost-benefit analysis estimates the (direct) net economic benefits to Canadian society that would result from new exports of natural gas compared with the alternative of keeping the gas to meet Canadian requirements in some future period.

While theoretically cost-benefit analysis could include consideration of environmental and other difficult-to-quantify costs and benefits, the Board has viewed cost-benefit analysis as an attempt to measure only the direct economic effects from the proposed exports, albeit from the perspective of society as a whole.

Cost-benefit analysis considers a project from the viewpoint of society and costs are included only if they truly represent the use of capital, labour, or other real resources due to the proposed exports. Payments incurred for expenses such as taxes are considered as transfers within the economy, and therefore are not considered costs to society.

The Board estimated the net economic benefits of additional natural gas exports on two bases:

(i) for each export application on a stand-alone basis (i.e. assuming no other exports would be approved), and

(ii) for alternative possible combinations of export licenses, including the combination approved in this Decision.

The reason for examining the net benefits of combinations of export projects is that many of the exports utilize the same pipeline system so that an interdependency exists among such exports. This means that the costs of two export proposals together are not necessarily equal to the sum of the costs of each proposal calculated on a stand-alone basis. Thus, the results of the stand-alone analysis cannot be used to select the best combination of exports. Nevertheless, the stand-alone analysis provides some insight into the economic attractiveness of the various export points. The methodology and results of the Board's stand-alone analysis are discussed in Sections 4.2.6.3 and 4.2.6.4. The discussion of the analysis of combinations of export licenses may be found in Section 4.2.6.5.

4.2.6.3 Approach of the Board's Stand-Alone Cost-Benefit Analysis

The conceptual approach adopted by the Board was to estimate the annual incremental costs and benefits that would result if a particular application for additional natural gas exports were granted. Annual net benefits were then discounted to a present value.

Estimated benefits of each export proposal were derived from the assumed revenue from the sale of natural gas in the export market plus the value of associated by-products.

To reflect the deliverability constraints identified above, export terms were adjusted to 10 years for renewals and 12 years for new licences, and Dome was examined for a 15-year export term. No new exports at Niagara Falls were allowed for prior to

November 1984. Columbia and Westcoast exports at Monchy were delayed to November 1983.

The costs directly associated with producing and delivering the proposed volumes to the export market included any incremental capital and operating expenditures that would be needed as a result of the export proposal. The Board's estimates of transmission costs were based on the estimates provided in the filed cost-benefit analyses and in the supplemental information provided by TCPL and Pan-Alberta. For each of the proposed exports at Emerson, transmission costs were limited to those that would be incurred on the TCPL Western Section and Emerson lateral. This implicitly assumes that exports through the Great Lakes system, to the extent excess capacity does not exist, will be accommodated for by an expansion of Great Lakes that is entirely paid for by the United States. It was also assumed that Alaskan gas will commence flowing through the Prebuild towards the end of 1989. Exports beyond 1989 were therefore assigned incremental capital and operating costs to the extent that they will require a further expansion of the Prebuild system.

The resource costs included costs for development, field equipment, natural gas processing plants, and gathering systems, as well as transmission costs attributable to additions to pipeline systems, and additional operation, maintenance, and fuel gas costs. Industry average producer costs based on estimates provided by TCPL were applied to all applications. For Dome, resource costs included, in addition to the above, costs for the LNG plant and for marine transportation. Producer costs were adjusted to account for assumed load factors of 95 percent for Dome and 83 percent for all exports to the United States. The Dome costs were adjusted to reflect the favourable interest rate on their Japanese loan. Costs incurred to date were viewed as sunk costs and were not included in the analysis.

The Board also evaluated the additional costs associated with new Canadian gas supplies and estimated the incremental cost to Canadians of having to use higher cost gas in the future as a result of exports over the near term. The Board's estimates of these costs were derived by comparing the estimated future annual costs of natural gas with and without additional exports. The Board has estimated that, in the absence of the exports authorized in this decision, the cost of gas would increase from about $.68 per GJ in 1982 to about $2.20 per GJ (in 1982 dollars) in 2005. Allowing for the new exports currently being authorized, the cost of gas is estimated to be of the order of $2.75 per GJ (1982 dollars) in 2005.

4.2.6.4 The Board's Stand-Alone Analysis of the Export Proposals

The Board's estimates of the benefit-cost ratio of each export proposal on a stand-alone basis using a real discount rate of ten percent are presented in Table 4.13. All of the benefit-cost ratios were significantly greater than one, indicating that all of the export proposals on a stand-alone basis are economically preferable to not exporting that gas at all. The Board's estimates are higher than those presented by A&S, due primarily to the A&S overestimate of user costs. The benefit-cost ratio of the Dome proposal based on a 15-year export term is significantly greater than unity, whereas the A&S estimate, based upon a seven-year export term and incorporating the high A&S estimate of user costs, was below unity.

The results of the Board's analysis agree with the general conclusions drawn by A&S; namely, early sales of gas are to be preferred to later sales, the use of existing facilities is more efficient than the use of new facilities, and gas for export that has to be hauled only a short distance in Canada will produce higher netbacks than gas that must be hauled a long distance.

The best rankings are generally achieved by the smaller exports at Emerson (which benefit from the significant excess capacity that currently exists in the TCPL Western Section) and early exports at Monchy (those that export a large amount of their gas prior to the commencement of Alaskan volumes). Moving down the list, the next group generally consists of exports at Aden, Cardston, Huntingdon and Kingsgate, and the larger exports at Emerson. The Sulpetro export at Niagara Falls also falls within this group. (Sulpetro's transmission costs were estimated on the same basis as all other proposals. Sulpetro's advantage compared to other Niagara Falls exporters is that their exports are both small and early).

Further down the list are the larger and later exports at Monchy. These exports require significant incremental facilities at the time the Alaska gas is assumed to begin to flow.

Next comes Dome and the exports at Niagara Falls. Unlike the A&S analysis, however, the Board's stand-alone analysis suggests that the Dome proposal is superior to the larger exports at Niagara Falls such as those of Pan-Alberta and TCPL/Transco. (This significant difference from the A&S evidence is, again, due to the assumption in the A&S analysis of a seven-year export term for Dome and to the high A&S estimate of user costs.)

Table 4-13

NEB COST-BENEFIT ANALYSIS ON STAND-ALONE BASIS

Export Proposal	Benefit-Cost Ratio	Export Term
ProGas GL-56 (Monchy)	3.67	1984-1989
ProGas GL-56 (Emerson)	3.62	1984-1989
Consolidated (Monchy)	2.92	1984-1989
Cdn-Montana (Montana)	2.88	1985-1992
Columbia (Monchy)	2.77	1983-1992
Consolidated (Emerson)	2.72	1984-1989
Sulpetro (Niagara)	2.68	1983-1991
A & S (Kingsgate)	2.60	1985-1992
ProGas New (Emerson)	2.60	1983-1995
Pan-Alberta (Kingsgate)	2.52	1988-1992
TCPL-Midwestern (Emerson)	2.50	1984-1992
Westcoast (Huntingdon)	2.49	1989-1992
TCPL-Mich.Wisc.(Emerson)	2.48	1984-1996
TCPL-Natural (Emerson)	2.48	1984-1996
ProGas New (Kingsgate)	2.46	1983-1995
Westcoast (Monchy)	2.18	1983-1992
Pan-Alberta (Monchy)	2.13	1987-1992
ProGas New (Niagara)	2.00	1984-1996
KannGaz (Niagara)	2.00	1984-1996
TCPL-Boundary (Niagara)	1.98	1984-1994
Dome (Grassy Point)	1.93	1986-2000
TCPL-Tennessee (Niagara)	1.92	1984-1994
Niagara (Cornwall)	1.90	1987-1992
Pan-Alberta (Niagara)	1.87	1984-1996
CDN-Montana (Niagara)	1.87	1986-1992
TCPL-Texas Eastern (Niagara)	1.85	1985-1997
TCPL Transco (Niagara/Emerson)	1.79	1984-1996
Ocelot (Niagara)	1.63	1985-1997

The rankings in Table 4-13 are based on each project's benefit-cost ratio. This ranking criterion is identical to that used by A&S, and was subject to discussion at the Hearing. A&S agreed with others at the Hearing that there are potential problems with any ranking criterion, and stated that the final test should be the maximization of the total discounted net benefits of the selected combination of export projects. The Board agrees with this view and notes that the rankings in Table 4-13 cannot be indiscriminately used to choose among export projects which seek to export different volumes at the same export point. The results of the stand-alone analysis were, however, useful as a basis for selection of the alternative combinations of export licenses which were further analyzed.

The Board also examined the effect of reducing the estimated direct labour costs to take into account the use of otherwise potentially unemployed resources, and found that there was very little effect on the benefit-cost ratios and no effect on the rankings.

4.2.6.5 Board's Analysis of Alternative Export Combinations

As a result of the limitations of stand-alone analysis, the Board also estimated the net economic benefits to Canada of export combinations. In view of the large number of export proposals, it was not possible for the Board to examine all possible combinations. The analysis therefore was restricted to an appraisal of several export scenarios that approximated the major choices facing the Board.

Since all of the combinations that were examined exported the same quantity of gas, it was possible to compare them on the basis of each combination's estimated net economic benefit, thus eliminating the need to rely on such ranking criteria as the benefit-cost ratio. Sensitivity analysis was undertaken using differing discount rates, 5 and 15 percent, and differing energy price forecasts. The Board also examined the effect of reducing direct labour costs to reflect the existence of high unemployment.

The combination of exports approved by the Board in this Report generated the highest estimate of net economic benefits of various possible scenarios. This result was true for all sensitivity cases.

Of the alternative combinations examined by the Board, the impact of substituting additional exports at Niagara Falls for exports of LNG to Japan was assessed. This combination showed net economic benefits which were lower than those associated with the exports approved in this Decision by a small amount. This is partly because this analysis assumed a lower price for exports to the United States than for LNG to Japan. In addition, such large exports at Niagara Falls would incur a very large incremental transmission cost which would most likely result in pipeline capacity significantly in excess of future domestic needs. The costs of such excess pipeline capacity would not then be offset by future savings to Canadians from use of the facilities to transport gas for domestic use. It should be noted that small changes in export prices or other difficult to predict factors could lower, erase, or reverse the small estimated difference.

The estimated values of the benefits and costs associated with the volumes of natural gas licensed in this Decision are shown in Table 4-14 below.

Table 4-14

ESTIMATED BENEFITS AND COSTS OF NEWLY AUTHORIZED EXPORTS ($ Billion)

(Present Value discounted at 10 per cent; constant 1982 dollars)

Benefits -	Revenues from Natural Gas and By-Products		32
Costs			
	Production	4	
	Transmission	3	
	Gas Replacement(1)	8	
			15
	Net Benefits		17

The net benefits to Canada of these exports are estimated to be of the order of $17 billion 1982 dollars.

4.3 Rationale for Allocation of Surplus

4.3.1 Amount of Surplus to be Licensed for Export

The Board has determined that under its Reserves Formula an amount of 18.4 EJ of gas is surplus to reasonably foreseeable Canadian requirements, plus an allowance for exports previously authorized. Under its Deliverability Appraisal the Board found that some 14.6 EJ could potentially be licensed up to the turn of the century. Some gas, however, is available before Applicants want it and

(1) This is the penalty for exporting low cost conventional gas now and replacing it with higher cost reserves in the future.

the time pattern of the available deliverability in later years does not exactly coincide with the needs of Applicants. Consequently, the Board deemed that an amount of about 12 EJ of natural gas is an appropriate amount to authorize for export at this time.

4.3.2 Approach to Allocation

The rationale for the Board's allocation rests on an assessment of the evidence and argument, the key features of which are summarized in preceding sections. It also takes into account the Board's objective of optimizing the net benefits to Canada of exporting this quantity of gas. The Board has assessed the overall net benefit to Canada of the licences it is prepared to issue, based on the net benefits to Canada flowing from each application on a stand-alone basis. The Board has also compared the composite net benefits of the package of licences it proposes to issue with other possible combinations of licences in order to assess their relative attractiveness to Canada.

In reaching its Decision, the Board has also taken into account the marketability of Canadian natural gas in the United States and in Japan as well as supply, deliverability, pipeline, tariff, financing, and Canadian public interest matters, not all aspects of which can be fully reflected in a cost-benefit analysis. In consequence of these other difficult-to-quantify factors, the ultimate decision must, of necessity, devolve to one of judgment by the Board.

4.3.3 Criteria for Allocation of Available Surplus

The first consideration in the allocation process was the obligation to continue, where appropriate, to supply existing markets. Canada has been exporting gas to the United States since 1952 and has been a secure and reliable supplier of gas to a growing number of importers and markets since that time. Canada intends to continue to be a secure and reliable supplier, and the Board believes that existing markets, which can demonstrate the need for the gas, should have an assurance of a continued supply for some ten years ending 31 October 1992.

The second allocation criterion related to new markets requiring new facilities, whether in Canada or in the United States. The Board believes that the financing of new facilities generally requires a minimum of twelve years supply of gas. The Board is, therefore, prepared to issue new licences for twelve years from the expected first flow of natural gas for acceptable applications that involve the construction of new facilities in Canada, in the United States, or in both countries. In those cases where the indicated commencement date of export appears now to be unrealistic, the Board has delayed the date of commencement of the licence by one year without altering the duration of the licence.

A minor adjustment has been made to this Decision criterion in that some licences have been phased down in the last two or three years of their terms in order to correspond more closely with the forecast deliverability of natural gas and, where appropriate, to permit a gradual transfer of the facilities to service Canadian needs. In general the ten and twelve year criteria enunciated above produce a result which corresponds closely with the amount of gas shown to be available for export in each year under the Board's Deliverability Appraisal.

In the case of Dome's proposed export of LNG to Japan, special considerations were warranted because of the large expenditures for the pipeline and LNG plant in Canada, and for the regasification, storage, and other facilities of the customers in Japan, and because 20-year contracts for the time charter of ships were said to be highly desirable.

The Deliverability Appraisal does not appear to provide a basis for the issuance of a long-term licence. However, considering that:

(1) all of the gas for which the Board might issue licences to Dome and other Applicants may not be exported; and

(2) there is a portion of the gas found to be surplus which has not been allocated;

the Board is confident that there will be gas available for delivery beyond the point indicated in the Deliverability Appraisal. The Board is, therefore, prepared to consider issuing a licence to Dome for a 15-year period.

4.3.4 Marketability in the United States, Pricing and Netbacks

An assessment of the United States market for Canadian gas is particularly difficult at this time because the future pricing régime for United States gas is unclear. Nevertheless, the evidence suggests that the present surplus of United States indigenous gas available at prices below competing fuels could disappear in two to five years. The present situation is largely sustained by rapid depletion of offshore Louisiana fields under contracts with high rates of take, and its continuation depends on the discovery of new fields to replace those being depleted quickly.

Should the finding rate not be maintained, the low reserves-to-production ratio of most major interstate pipelines could result in the surplus of low-cost gas in the early 1980's turning into a shortage by the mid-1980's. While there are likely to be few opportunities in the next two years to make new sales or even to increase sales of Canadian gas which has already been licensed the Board believes that the United States will provide major opportunities for the sale of Canadian gas over the medium and longer term. Very little of the gas proposed to be exported as a consequence of this Decision will move to market in the next two years. New pipeline capacity to move gas to new markets is unlikely to be in place before the end of 1984 and few of the licence extensions take effect until later in the 1980's.

As pointed out in Section 4.2.1, the most attractive growth markets are in the Northeast, that is, the New England and Mid-Atlantic regions, with reasonable prospects in the North-Central region of the Midwest. Prospects for growth of the market in California are questionable and there would appear to be little hope of regaining much of the market lost to high sulphur heavy fuel oil in the Pacific Northwest.

More detailed consideration of the Northeast area follows in Sections 4.3.8 and 4.3.11.

In the United States, the competitiveness of Canadian natural gas is determined by its cost in the eventual marketplace. This is the sum of the price at the international boundary plus the cost of transmission in the United States from the specific point on the international boundary to the market area concerned. If there is any choice of boundary point, the importer obviously prefers the one where the United States transmission cost is less - the one geographically nearest his market.

United States pipeline companies have in the past been able to roll in Canadian gas with lower-cost indigenous gas, thus achieving a lower average cost of gas giving it the ability to compete with other fuels. The increasing reliance by United States pipeline companies on "new" gas, the price of which is governed by the provisions of the Natural Gas Policy Act, is dissipating their ability to absorb Canadian gas. This factor, combined with the current export price for Canadian gas exports, a price which, at the behest of the United States, is uniform at all export points, and a price which was initially determined more by the cost to Canada of replacing exported gas with imported oil than by competitive market factors, is making Canadian gas less competitive in United States markets.

On the Canadian side of the border, the producer is seeking the highest profit and hence prefers the lowest cost of transmission to the international boundary. This generally means a preference for sales at the point on the international boundary nearest the producing province. However, the most attractive new markets for Canadian gas happen to be farthest from Canada's producing areas.

As indicated above, this Hearing was based on the existing pricing régime of a uniform border price. The trend in the United States towards some form of deregulation and competitive pricing, however, was much in evidence.

While the Board has based its decision on the continuation of a uniform border price, it has recognized that such a pricing system may not, in fact, prevail throughout the life of the licences it will issue. The Board, therefore, has analyzed the situation and believes that a pricing régime based upon variable border prices would not have altered its Decision. The marginal market in terms of net benefits to Canada under the proposed licences would remain the Northeast market because of the long distance from source of supply to market, and because extensive new pipeline capacity would have to be constructed. The dominance of these two factors would prevail under any pricing system.

4.3.5 Criteria Concerning the Supply of Gas, Producers and Exporters

Before an export may take place, an exporter must have, in addition to a licence issued by the Board, a removal permit from the province in which its gas supply is located. Not all of these permits had been obtained when the Hearing closed. Nevertheless, considering that the quantity of export authorized is about 12 EJ compared with the surplus of 18.4 EJ determined under the Board's Reserves Formula, serious problems are not anticipated in this respect.

The Board also considered more specific points on this matter. It has been conscious of the need of small producers to generate cash. In this respect, the application of KannGaz represents an imaginative proposal by about 44 participants involving some 250 small producers for the export of gas that might otherwise have remained undeveloped. Similarly, Sulpetro's application relates to production involving some 32 producers.

The proposal by Ocelot for the export of gas by small producers in Saskatchewan is the first export proposal received from that province. The Board believes it to be beneficial to have these reserves developed. The export application of Ocelot, however, was the lowest in ranking in the

cost-benefit analysis due, in part, to the fact that the export would occur at Niagara Falls, Ontario and in part to the high cost of developing the reserves and connecting them to the TransCanada system.

A more significant consideration relates to the fact that Ocelot proposes to export gas from a province which currently imports a substantial proportion of the supply for its own provincial requirements from Alberta. Approval of this application at this time would have the effect of permitting Saskatchewan to export its gas at the higher export price while at the same time fulfilling a large part of its own requirements with Alberta gas purchased at the lower domestic price. While some discussions had taken place between the governments in order to arrive at a working solution to the sharing of the export flow-back, no agreement had been reached by the close of the Hearing.

Several parties expressed the view that the flow-back issue was irrelevant to the issues before the Board and that in any event the Board did not have the authority to deal with the question of flow-back at all.

The Board cannot agree that an absence of an agreement for the equitable sharing of revenues accruing from export sales from a net importing province is irrelevant to the issue of whether or not to authorize an export licence. The Board does not believe that the approval of a proposal for the export of gas from a net importing province is in the national interest when there is no arrangement in place between that province and the province from which it imports the bulk of its domestic requirements for the equitable sharing of the higher export revenues. Simply because a cost-benefit evaluation might result in a value greater than unity does not compel the Board to issue a licence. The national interest must also be construed in terms of the harmonious interaction between the provinces in respect of the interprovincial and international trade in natural gas. The Board considers that the potential for dispute in these international and interprovincial flows of gas which might attend the authorization of such an export in the absence of a flow-back sharing agreement is highly relevant to the national interest and to the decisions it is required, by statute, to make.

In taking this position the Board makes no attempt to prescribe how the flow-back should take place. In that limited respect the Board is in agreement with the position taken by the parties at the Hearing. The Board's concern that an agreement exist between the provinces for the export flow-back, however, is quite different from an attempt to prescribe how such flow-backs should take place. For the purposes of an export authorization, the Board expresses no view as to whether the Energy Administration Act would govern the situation envisaged by the Ocelot application. The concerns noted above, however, are relevant to the question of whether to authorize these volumes of gas for export.

The Board, for the foregoing reasons, and in particular in view of the absence of this interprovincial agreement, is not persuaded that the approval of this application would be in the best interest of Canada. The application is therefore denied.

In closing, however, the Board would like to indicate its support for Ocelot's attempt to market Saskatchewan gas in the United States. As noted above, this application contains several features beneficial to the Canadian public interest. The denial of the instant application should not be taken to preclude the possibility of a successful application for the export of Saskatchewan gas at some point in the future.

4.3.6 Criteria Concerning Existing and New Pipelines

In arriving at its Decision, the Board gave considerable weight to optimizing the use of existing pipelines, expecially those with spare capacity or cheap expansibility, in preference to building expensive new pipelines. The lower cost of transmission on existing, partially depreciated systems, built when costs were lower, has the twin effect of increasing the netback to producers and improving the marketability of Canadian gas in the United States. In this regard, the Board also favoured exports at points close to the producing province to minimize costs of transmission in Canada.

In addition, the Board considered the degree to which facility additions to existing pipelines could be used to serve future Canadian needs as export licences expired.

Turning first to the Canadian scene, Westcoast has spare capacity on its pipeline because of the decline in sales to the United States Pacific Northwest. This spare capacity could be used to transmit gas to the new market involved in the application to the FERC by Northwest for an offline sale of 300 MMcf ($8.5 \times 10^6 m^3$) per day of gas to Texas Eastern.

Special considerations also apply to the existing capacity on the prebuild sections of the Alaskan

Natural Gas Transportation System. The completion of the ANGTS has now been delayed until 1989. The prebuild pipeline, designed for approximately two Bcf ($56.6 \times 10^6 m^3$) per day of Alaskan gas, is currently carrying a much smaller volume of Canadian gas. The licences for gas already being carried can be extended without incurring any incremental capital cost until Alaskan gas flows which would also have the effect of increasing the unit netback to producers of the exports already licensed over this system. If additional throughput capacity is required in the prebuild pipeline, it would need at most small capital cost additions, such as for compressors.

On the other hand, the expansion of the TransCanada pipeline system to transmit gas to Niagara Falls, Ontario, for sale in the United States Northeast would be costly. This is because significant new pipeline facilities would be required over a distance of some 3 000 kilometres from Alberta to Niagara Falls.

The economics of a large-scale expansion of the TransCanada pipeline system to transmit exports are unattractive because it is unlikely that the slowly growing domestic demand will be able to absorb the surplus capacity left in the TransCanada system when the export licences expire.

There are added complexities relating to a major expansion of the TransCanada pipeline system for the export market. If the present cost allocation method were to be continued, based on a system-wide allocation, then the rolled-in cost to Canadians would increase and if the current gas/oil price relationship were maintained, the federal natural gas and gas liquids tax would be reduced accordingly.

It is the Board's view that most of the general principles applicable to minimizing pipeline costs in Canada would probably apply equally in the United States. If the uniform border price were no longer to prevail there would be an incentive to seek to minimize transmission costs in the United States as well as in Canada. In this regard there would appear to be an advantage to maximizing throughput on the ANGTS prebuild pipeline facilities in the United States. The present tariffs on the prebuild pipeline facilities in the United States are high, not only because of the lack of definitive gas sales contracts for the supply of Alaska gas, but also because of the front-end loading characteristic of the traditional gas pipeline toll design. It appears to the Board that expanding the system at low incremental cost and using spare capacity would reduce the cost to the United States end-user and thereby improve the marketability of Canadian gas

A further factor limiting the markets accessible to Canadian gas is the current termination of the Northern Border pipeline at Ventura, Iowa. Extension of the pipeline to Dwight, Illinois, now, rather than, as planned, when Alaska gas flows, would provide access for Canadian gas to additional United States markets. The increase in throughput would result in lower unit costs of transportation benefitting both existing and future purchasers of Canadian gas.

In summary, the Board's Decision has given considerable weight to minimizing pipeline transmission costs.

4.3.7 Market Ordering - First Phase

The first steps in the allocation process involved:

1. assuring continued supply to existing markets for ten years;

2. providing licences requiring new facilities to serve new markets in the United States with terms of twelve years and to Japan with a term of fifteen years;

3. considering, with respect to each application, the marketability of Canadian gas as well as supply, pipeline, financial, and Canadian public interest aspects; and

4. ranking applications using cost-benefit analysis considering each application separately.

Based on these criteria, and subject to the phase-down outlined earlier, surplus was allocated to meet the requirements in this time period of all applications for export to the United States, other than for those to the United States Northeast. As noted elsewhere in this Chapter, however, some applications were denied for other reasons.

This has resulted in the approval of the following exports for which the Board is prepared to issue licences:

Alberta & Southern at Kingsgate, to Pacific Gas Transmission;

Canadian-Montana at Aden and Cardston, to Montana Power;

Columbia at Monchy, to Texas Gas Transmission;

Consolidated at Emerson, to Northern Natural;

Consolidated at Monchy, to Northern Natural;

Pan-Alberta at Kingsgate, to Northwest Alaskan;

Pan-Alberta at Monchy, to Northwest Alaskan;

ProGas at Emerson, to Texas Eastern et al;

ProGas at Monchy, to Texas Eastern et al;

TransCanada at Emerson, to Natural Gas Pipeline;

TransCanada at Emerson, to Michigan Wisconsin;

TransCanada at Emerson, to Midwestern;

Westcoast at Huntingdon and Kingsgate, to Northwest; and

Westcoast at Monchy, to Texas Gas Transmission;

The major remaining decisions related to whether and, if so, how much, gas should be licensed for sale in the United States Northeast and whether the Western LNG Project should be approved. These are reviewed separately and then the relative merits of the two are compared.

4.3.8 The United States Northeast Gas Market

A previous section of this Chapter indicated that the United States Northeast market, comprising the New England and Mid-Atlantic regions, requires additional gas supply, and consequently is a growth market. It was also considered probable that competitive conditions would allow this market to pay a slightly higher price than other markets. The Board, therefore, has no reservations about the quality of this market.

The export applications indicate that it is proposed to build new pipeline capacity on the TransCanada system from Alberta to Niagara Falls, Ontario, as well as new pipeline facilities in the United States. As previously indicated, new pipelines are expensive to build. The key questions are, therefore: first, is it economic to serve the market, bearing in mind the availability of gas over a twelve-year term; and second, how much of the market should be served? This in turn raises the question of the extent to which the facilities required for the export market would subsequently be needed to serve the Canadian market. It appears to the Board that a limited allotment of Canadian gas to supply the United States Northeast market would be consistent with the related facilities being required subsequently to serve the Canadian market.

Cognizance has also been taken by the Board of the possibility of Sable Island gas serving a portion of this market by the late 1980's. Arctic Island and Hibernia gas are also potential sources of supply at some undetermined point in the future.

All exports to the Northeast region from Niagara Falls, Ontario, while ranking behind most other United States exports on a stand-alone cost-benefit analysis, showed positive benefit-cost ratios (ranging from 1.6 to 2.7).

In summary, despite the attractiveness of the Northeast market, because of its distance from Canada's producing areas, the need for extensive pipeline expansion in Canada and the associated desire to optimize the transfer of such facilities to Canadian use, the need for new pipeline facilities in the United States, and uncertainty concerning the appropriate future source of supply for this market, the Board deems it prudent to make only a limited commitment to this market at this time.

4.3.9 The Western LNG Project

The Western LNG Project appears to provide an opportunity to diversify the markets for Canada's exports of natural gas.

The planning of the Project is well advanced, it contains innovative features, and is being undertaken in conjunction with NIC Resources Inc., the wholly-owned Canadian subsidiary of an experienced Japanese company, Nissho Iwai, and five reliable Japanese customers. It is based on twenty-year contracts, with a selling price close to crude oil equivalent at the Japanese port, and a virtually 100 percent take-or-pay load factor. The Board is satisfied with the contractual basis of the sale of the gas to the Japanese customers.

The Board is aware of major current and prospective projects involving LNG supply to Japan by other countries. These may exert downward pressure on pricing in the long term; however, due to its firm long-term contract, the Western LNG Project price will retain its relationship to the world crude price. The Board is also aware that the time frame within which this project can proceed is limited and an extended delay in regulatory proceedings could jeopardize it.

The present surplus of LNG shipping provides the flexibility to use either existing or new ships or a combination thereof. The Board accepts that Dome has not yet reached the optimum point to make a choice and commit to build new and/or charter existing vessels. The Board is also aware that little direct Canadian content can be expected from the shipping part of the project, although Canadian content offsets may well be possible.

The LNG plant facilities, however, provide both a high Canadian content and an opportunity to joint venture on the design and engineering aspects and thereby to acquire a degree of technological capability not now available in this country. The development of such a capability might prove to be beneficial if other sources of Canadian gas were to be moved to market in the form of LNG.

The pipeline would have virtually 100 percent Canadian content and involve conventional construction techniques.

Financing is likely to be available from Japanese sources on attractive terms for the LNG plant, but final agreement had yet to be concluded when the Hearing ended.

The more controversial aspects of the project relate to the economic assessment. This is based primarily on a flow-back to Alberta and British Columbia producers derived from the C.I.F selling price. The C.I.F price is subject to adjustment over time: 50 percent on the basis of changes in the export price of natural gas at the Canada/United States international boundary and 50 percent based on the change in price of a basket of crude oils.

From the C.I.F sales revenue are deducted the cost of chartering and operating five LNG tankers, the cost of service of the plant, and the cost of service of the pipeline to transmit the gas from Alberta and British Columbia to the plant. Some intervenors expressed concern that the resulting netback would be below the netback for gas sold in the domestic market. Specific arrangements had not been reached on the supply of the gas with the Governments of Alberta or British Columbia at the time the Hearing closed.

Evidence was given on the risk of cost overrun on both the plant and pipeline with the Applicant indicating a high probability of cost underrun. Construction cost incentive schemes were tentatively proposed at the Hearing. A hearing under Part III of the NEB Act will be needed to fully assess all the facility aspects of the Project. Conditions would need to be included in any certificate in order to ensure that effective cost controls and incentives be in place before construction could commence.

The cost of service tariff was based on a deemed capital structure of 65 percent debt and 35 percent equity rather than the actual financing based on virtually 100 percent low-cost Japanese debt, provided that no construction cost overruns needed to be financed. Some tariff levelling was proposed, but whatever the tariff the Board approved, Dome and its partner indicated that they would not proceed with the project unless the net cash revenues corresponded approximately with those derived from the tariff proposed by Dome. These cash revenues provided for the retirement of the Japanese debt over a ten-year period. The tariff contained innovative features not usually contained in conventional tariffs and appeared to provide a somewhat high return in relation to the risks identified by Dome based on a firm 20-year licence. Since the Board is not prepared to issue a firm licence for longer than 15 years, and since the specific terms of the Japanese loan are not known, nor are the terms and conditions of the supply of the gas from Alberta and British Columbia, the Board does not take a definitive position on the LNG plant tariff at this time. Rather, the Board believes the matter should be dealt with in a Part IV hearing on the form and content and other aspects of the tariff when all pertinent information is available.

Dome assumed that the tariff for the Westcoast pipeline would be a traditional variable cost-of-service tariff with some degree of levelling. Westcoast was not, however, prepared to commit to build the pipeline or to the tariff until a transportation agreement had been signed with Dome. Again, a Part IV hearing will be needed to approve the form and content and other aspects of the tariff.

From a supply viewpoint, the project is based on 75 percent of the gas being supplied by Alberta and 25 percent by British Columbia. The British Columbia Government has strongly endorsed the Project on this basis. Some flexibility in the proportion of gas supplied from each province could contribute to alleviating the decline in British Columbia exports to the Pacific Northwest.

The Board decided that if its analysis of the Western LNG Project led it to the conclusion that the Project was in the Canadian public interest, the Board would be prepared to earmark or set aside 0.9 EJ of the unallocated surplus from the Reserves Formula to support the financeability of the Project even though such an allocation is not justified at this time by the Deliverability Appraisal. A subsequent licensing of this earmarked gas would require the demonstration, to the Board's satisfaction, of the development of deliverability to support the continuation of the 15-year licence for a further five-year term. The Board does not wish to be placed in the position of frustrating an export judged to be in the Canadian public interest, particularly when, in the case of the Western LNG Project, the protection of Canadian requirements is assured by the conditional nature of the further commitment of

gas to the Western LNG Project. The Board believes this unusual treatment to be warranted by the circumstances of this particular application.

Taking into account all of the above factors, and ignoring for the moment the comparison with pipeline sales of gas to the United States Northeast, the Board, assuming a favourable outcome of outstanding matters, is favourably disposed to the issuance of a licence to the Western LNG Project.

The economic attractiveness of the project depends to a large extent on the world price of crude oil over the next 20 years. The costs of shipping, liquefaction and transmission are significant but relatively fixed in nature, consequently the producer netback greatly depends on the forecast of the price of world crude oil. The risks of the project, therefore, primarily relate to the selling price. The Board believes that the decision to proceed with the project should rest primarily with the investors, Dome, NIC, and Westcoast as well as the provinces and producers supplying the gas. The views of these parties are not fully known at this time.

4.3.10 United States Northeast Gas Market Versus the Western LNG Project

As indicated earlier, a major decision facing the Board was either to approve the Western LNG Project and to license only a limited portion of the applied-for gas to the United States Northeast during the period for which the Board was prepared to issue licences, or to deny the Western LNG Project and to license more of the applied-for gas to the United States Northeast.

A starting point for this was a review of the stand-alone cost-benefit analysis (See Table 4-13). This clearly indicates that the Western LNG Project yielded a higher cost-benefit ratio than all but four of the applications to export gas at Niagara Falls, Ontario.

A further cost-benefit analysis was conducted of two cases, one where all the residual exports took place at Niagara Falls, and a second case for the same absolute volume of exports but substituting exports via the Western LNG Project for an equivalent volume of exports at Niagara Falls, as discussed in the section on cost-benefit analysis. This comparative analysis indicated a small net benefit in favour of the Western LNG Project. This result was subjected to various sensitivity tests based on varying discount rates, the world crude oil price, and adjustment for unemployed labour. All of these sensitivity tests confirmed a small net benefit to Canada in favour of the Western LNG Project. These results are conditional on the LNG Project shipping, liquefaction and pipeline costs being within the estimates provided by Dome at the hearing and on the ability of TCPL to expand its system at the cost estimated by that company. They are also conditional on the particular assumption used with respect to the price of gas exports to the United States. If a higher price for United States exports had been assumed the difference in the cost-benefit results could have been erased or reversed.

However, analysis of netback to producers from either project under a low price world crude oil scenario showed that the netback could be below that received from domestic sales of gas in some years. (See Table 4-10).

The viability of the projects from the perspective of the parties involved may depend, therefore, on the ability of the various participants to come to a mutually satisfactory agreement on the distribution of the revenues.

Next, broad factors not fully reflected in the cost-benefit analysis were considered. These included diversification of the export market for Canadian gas, the fact that the Western LNG project already had the strong endorsement of the British Columbia Government, and could go a long way to resolving the problem of finding a market for surplus British Columbia gas.

With respect to the United States Northeast gas market, a very large export to this region would raise grave doubts whether this market would continue to be optimally served by Alberta gas beyond the period covered by the Board's Decision, and would raise doubts as to when the pipeline facilities used to transmit the gas would ultimately be needed to serve the Canadian market. Furthermore, the availability of Sable Island gas and the potential for other East Coast and Arctic supplies over the long term raise questions as to the desirability of a very large commitment of Alberta gas to this market at this time.

For all the above reasons, the Board is prepared to issue a licence for the export of gas to the Western LNG Project. In order that the Board may ensure that this export takes place on substantially the same basis as that approved by the Board in this decision, it will be necessary to condition the licence in such a way that no export may take place until a number of conditions have been met.

The Board will first require that certain approvals and agreements which were not available in their final form at the Hearing be filed prior to 31 January 1984 or such later date as the Board may, upon application, specify. This is necessary in order to ensure that all important outstanding details are finalized and that all cost and revenue parameters are sufficiently well-defined at an early date in order to enable Dome to proceed with the project and commence deliveries at the earliest opportunity. The requirement that the concurrence of the Alberta and British Columbia governments be obtained and that the major Part III and Part IV matters be settled should assist the various participants in arriving at the mutually satisfactory agreement on revenue distribution noted above.

Although no longer required by the Act to satisfy itself that the export price charged by an applicant is "just and reasonable in relation to the public interest", it is implicit in the Board's decision to issue a licence to Dome that the export price for the sale of LNG is acceptable to it. The Board takes this view in recognition of the fact that the export price is, in effect, calculated by deducting from the C.I.F. sales price paid by the Japanese buyers, the transportation, insurance and management and administrative charges set out in the F.O.B. Sales Agreement. For this reason, the Board has included a condition in the licence which sets out the means by which the export price to be paid at the international boundary is calculated.

Since the level of the C.I.F. price to be paid by the Japanese buyers is critical to the approval of this export, a further condition has been imposed which would prohibit any export in accordance with changes to the LNG Sales Agreement (for example a change to Article X "Contract Sales Price") unless those changes were first approved by the Board. As the export price is equally sensitive to the costs of shipping and insurance and the management and administrative charges which are deducted from the C.I.F. price to result in the "Contract Sales Price" paid by the Dome-NIC joint venture to Dome under the F.O.B. Sales Agreement, the latter Agreement will also be subject to the same condition.

While the price to be paid for an export of gas is obviously critical to an evaluation of its net benefits, both on the basis of a cost-benefit analysis and an assessment of other non-quantifiable factors, should for any reason this export price be significantly reduced it would necessarily affect the attractiveness of this export to Canada as a whole. In view of the direct impact that the costs of shipping and insurance and the management and administrative charges have on the export price, the Board has provided for a review of these costs, fees and charges in the price condition which it will include in the licence. In this manner it should be possible to ensure that the price paid at the international boundary is calculated on the same basis as that presented at the Hearing.

In taking this position, the Board does not purport to in any way interfere with the C.I.F. price negotiated with the Japanese buyers nor the costs of shipping and management fees paid in respect thereof. The Board, however, takes the view that it is incumbent upon it to ensure that, where the export price is calculated in accordance with a formula, the various components of that formula are consistent with representations made as to their magnitude at the Hearing at which the export itself was approved.

The Board has also decided to include a condition in the licence requiring that the relevant shipping agreements be filed with the Board prior to any exports taking place and that all amendments or changes to any of the contracts or agreements filed at the Hearing or to be filed in accordance with the conditions of the licence shall be filed with the Board. In addition, the informational requirements imposed as a condition of the licence will further permit the Board to fulfill its regulatory responsibilities in respect of not only the plant and pipeline but the export price to be paid for the sale of Canadian gas to Japan.

In view of the quantities of gas which the Board has found to be surplus to reasonably foreseeable Canadian requirements, it is possible at the same time as granting a licence to the Western LNG Project, to authorize the export of a reasonable proportion of the applied-for volumes for gas for sale in the United States Northeast.

4.3.11 Allocation Within the United States Northeast Gas Market

The first step in considering how to allocate gas to Applicants in the Northeast was to resolve the issue of whether the decision rested on other than market considerations. As indicated earlier, the Board is prepared to license the full quantities of gas applied for by KannGaz and Sulpetro, and to deny at this time the Ocelot application.

The resultant applications for the period for which the Board is prepared to issue licences amounted to twice the volume of gas available. The Board then reviewed the various marketability factors relating to Algonquin, Transco, Texas Eastern, Tenneco and Boundary Gas. While differences in their contracted United States supply and other market factors exist, as set forth in Section 4.2.1,

the Board found little to choose between the importers and views all of them as desirable importers of Canadian gas. The Board, therefore, allocated to each of them 50 percent of the quantities each applied for during the period for which the Board was prepared to issue licences.

4.3.12 The Special Situation Regarding British Columbia Gas

Because of the special difficulties being experienced in exporting gas of British Columbia origin, this situation is now reviewed in total even though partially covered earlier. The main opportunity for the export of British Columbia gas has, to date, been the United States Pacific Northwest. In recent times this market has declined significantly, partly related to the temporary curtailment of British Columbia gas following the failure of the Beaver River field in 1973, and partly because of the combination of the border price and the regional economic recession in the Pacific Northwest making gas less competitive with high sulphur fuel oil. This fuel oil has sought to clear the market at prices well below the export border price for gas. The absence of an adequate take-or-pay clause in the Westcoast/Northwest Pipeline contract has compounded the problem of maintaining the market share of British Columbia gas. However, it is doubtful if significant portions of the Pacific Northwest market could be re-acquired in view of the abundant supplies of high sulphur fuel oil available at low prices in this region.

To offset the immediate effect of this decline in the market in the Pacific Northwest, Westcoast, in conjunction with Northwest Pipeline, has been endeavouring to arrange for offline sales.

The first attempt was a contract for a 200 MMcf ($5.7 \times 10^6 m^3$) per day best efforts sale by Northwest Pipeline to Texas Eastern. This proposal was withdrawn due to protracted regulatory proceedings in the United States. The proposal was then amended to a 300 MMcf ($8.5 \times 10^6 m^3$) per day firm sale. This application is currently before the FERC. However, a FERC decision is not expected soon and, given the present climate, the outcome is uncertain. The Board in its Decision has indicated its willingness to license gas for such an arrangement over a twelve-year period to support the new pipeline capacity needed in the United States. This sale is important to the future health of the British Columbia natural gas industry.

However, the Board continues to have concern regarding the uncertainty of United States regulatory approvals authorizing both the offline sale to Tetco and the construction of the necessary United States pipeline facilities to effect this sale. Thus the Board believes that it would be appropriate in the circumstance of Westcoast's export application to issue a separate export licence corresponding to the offline sale. Such a licence would be conditional upon Westcoast satisfying the Board that all necessary United States regulatory authorizations had been received. Accordingly, the Board would issue two new export licences to Westcoast commencing 1 November 1989 for the total 785 MMcf (22 229.4 $\times 10^3 m^3$) per day being applied for. One licence would be for 300 MMcf (8 498.4 $\times 10^3 m^3$) per day for an offline sale by Northwest to Tetco, the other would be for 485 MMcf (13 731.0 $\times 10^3 m^3$) per day for sale to Northwest at Huntingdon and at Kingsgate, and to Texas Gas at Monchy.

The opportunity for further penetration of British Columbia gas into the United States at this time seems to be limited, given the slow growth of markets in California, coupled with the present pattern of gas transmission facilities linking each producing province with individual United States markets. However, in the Board's view the ability of British Columbia gas to penetrate the Southern California market would be impeded by the sale of Alberta gas by ProGas to Transwestern. Since the opportunities for British Columbia gas to serve United States markets within reasonable distance of its borders are limited, the Board is not prepared to approve the ProGas sale to Transwestern at this time.

The British Columbia surplus gas problem could be further alleviated if significant additional British Columbia supply were to be directed to the Western LNG Project. Although the overall requirement for the Project exceeds the surplus indicated to be available from British Columbia supply, additional gas might become available due to a limitation in conventional exports to the United States.

4.3.13 Special Considerations With Respect to Certain Applications

Niagara Gas applied for an extension to its licence to export natural gas at Cornwall, Ontario to St. Lawrence Gas in New York State. This is a small border accommodation and wholly dependent on Canadian supply. Because of the distance from Alberta, the netback is not favourable but the Board is prepared to continue the border accommodation and to extend the licence to 31 October 1992.

The Board, as indicated in the previous section, is prepared to approve the export of Yukon gas from

the Kotaneelee field by Columbia to Texas Gas Transmission at Monchy by means of displacement of gas by Pan-Alberta. This export benefits the Yukon as there is no other market for the gas, and it also benefits British Columbia by backing out equivalent volumes of Alberta gas being taken by Westcoast under a contract with Pan-Alberta. Texas Gas has demonstrated a need for the gas to the satisfaction of the Board.

TransCanada applied for a licence to export gas to Transco at Emerson, Manitoba and Niagara Falls, Ontario. As well Transco applied for a licence to import a portion of this gas at Sarnia, Ontario and to re-export a like amount at Niagara Falls, Ontario. The Board has decided that because the quantities proposed to be exported by TransCanada at Emerson to Transco are the subject considered of Transco's import/export application, these will be considered as Niagara Falls exports for the purpose of allocation in this Decision. As noted in Section 4.3.11 above, the Board has decided to allocate to some Niagara Falls applicants 50 percent of the applied-for quantities and this will apply to the TransCanada and Transco applications.

The application of Union Gas to extend exports of synthetic natural gas to Transco is unlike other applications in that the gas is derived from crude oil. The Board considers the volumes applied for to be surplus to reasonably foreseeable Canadian requirements. However, the Board is cognizant of the fact that under certain circumstances the deliverability provided by this source may be required to satisfy Canadian requirements. As a consequence the Board is prepared to issue a new licence to succeed Licence GL-64 with reduced levels during the last two years.

4.3.14 Terms and Conditions in Licences

The Board will in general be basing the terms and conditions in its licences on those contained in the contracts between the exporter and importer. The Board believes that this approach will be beneficial in a climate where competitive market conditions appear to be increasing in importance. As stipulated by Section 35 of the Part VI Regulations, those provisions in the contracts which were filed in the Hearing and now form the basis for the issuance of licences cannot now be changed without the concurrence of the Board, without prejudicing the licence. Where licensed volumes in this Decision are less than those contained in the export/import contracts, the Board will be prepared to consider the consequential amendment to those contracts.

A special word is needed, however, about take-or-pay clauses which the Board regards as fundamental to the financing of existing and new pipelines needed to deliver the gas to market. As suggested in the Phase I decision, the Board favours a reasonable level of take-or-pay in concert with the right of a one-year make-up at the end of the licence for gas paid for but not taken. This right of make-up would be limited to the annual volume in the licence. The Board is not generally in favour of a refund of all or part of the take-or-pay payments upon expiry of the licence. However, the Board is prepared to accept the terms in the contracts for major licences where the take-or-pay level is at least 75 percent. As set forth in the Phase I decision, the take-or-pay situation in respect of Westcoast's Licence GL-41 remains to be resolved .

Tolerances and other minor licence matters will be dealt with in the disposition of each licence application (Chapter 5).

Two specific licensing matters warrant special attention. First, in its application, Niagara Gas indicated that upon receipt of the authorizations requested, it would consent to the revocation of Licence GL-6. As outlined in Chapter 5, however, the Board has not approved for export the quantities requested by Niagara Gas and has therefore decided that the new licence to be issued to Niagara Gas should not take effect until Licence GL-6 has been revoked.

Second, under cross-examination by Board Counsel and in argument, Pan-Alberta indicated that it was agreeable to the consolidation of Licences GL-58 and GL-62 into one licence and GL-59 and GL-63 into another licence. The Board has decided not only to consolidate these licences as outlined above, but to incorporate the authorizations granted in this Decision (see Chapter 5) into those consolidations. In view of the possible complications involved in any consolidation of existing and recently issued export authorizations, the Board will circulate draft licences to Pan-Alberta for its review prior to their issuance.

As a final matter, the Board has decided that for the present time it is most appropriate to continue its current practice of including the export price as a condition of the licence.

CHAPTER 5

Decisions

5.1 Introduction

Having taken into account all the matters which appear relevant, the Board concludes that it would be in the public interest to authorize new exports of natural gas. The Board is, accordingly, prepared to issue licences and licence amendments authorizing the export of some 12.2 EJ of gas to United States and Japanese markets. A tabulation of new exports by Applicant is shown in Table 5-1.

In addition, the Board is prepared to issue a licence to Union Gas to export 64 PJ (1.7 $10^9 m^3$) of synthetic natural gas, a by-product of the operation of the Petrosar plant; and to issue an import/export licence to Transco for the movement of 614 PJ (16.3 x $10^9 m^3$) of natural gas through Canada from a point near Sarnia to Niagara Falls. Union Gas had applied for 80 PJ (2.1 x $10^9 m^3$) and Transco had applied for 2 336 PJ (62.2 x $10^9 m^3$).

The Board conducted a benefit-cost analysis of its Decision, finding that net economic benefits having a present value of some $17 billion, would accrue to the Canadian economy as a result of the new export authorizations. These net benefits include the effect on the economy of new exports compared with the alternative of keeping the gas in the ground until it could be used at some future time to meet Canadian requirements.

The necessary construction of gas production facilities, pipeline systems and liquefaction facilities means that these benefits will have significant and widespread impacts on various elements of the Canadian economy including employment, incomes, industry cash flow, revenues to governments and the balance of international trade. At the current export price of $4.94 U.S./MMbtu the contribution of the new exports to Canada's balance of payments during the term of the new licences would cumulate to some $70 billion over the term of these exports.

With respect to the terms of the licences to be issued, the Board believes it is important to assure continued gas supply to existing markets, and has approved all applications for extensions to existing licences for some ten years ending 31 October 1992, unless a shorter term was applied for. Where sales into new markets require new facilities, the Board deems twelve-year licences as necessary to support financing of such new facilities. In the case of LNG exports, the Board believes a minimum 15-year export term is necessary in order

Table 5-1

NEW EXPORTS APPLIED FOR AND APPROVED

	Applied For		Approved	
	Petajoules	$10^9 m^3$	Petajoules	$10^9 m^3$
Alberta and Southern	4 891	127.6	1 350	35.2
Canadian-Montana	514	13.8	113	3.1
Columbia	242	6.4	118	3.1
Consolidated	180	4.8	180	4.8
Dome	3 146	82.4	2 403	62.9
KannGaz	729	19.4	511	13.6
Niagara Gas	86	2.3	44	1.2
Ocelot	593	15.8	0	0
Pan-Alberta	4 621	122.5	2 217	58.7
ProGas	2 238	59.3	1 140	30.3
Sulpetro	175	4.7	175	4.7
TransCanada	6 482	172.3	3 049	81.0
Westcoast	2 644	67.8	930	23.9
Totals	26 541	699.1	12 230	322.5

for the project to be economically viable. To better match the new exports with the available annual deliverability, the Board decided that twelve-year licences should be shaped in order that they operate at the fully authorized level for a period of nine years, after which the daily and annual quantities will be phased down by 25 percent per year to provide for exports in the tenth year at 75 percent, 50 percent in the eleventh year and 25 percent in the twelfth year. For extensions to existing licences the phase-down concept will apply except that the general rule applied will allow for full quantities to 31 October 1990, with reductions to two-thirds in the 1990-91 contract year and to one-third in the contract year ending 31 October 1992.

The Board notes that Applicants have not contracted for sufficient gas supplies to fully meet their annual requirements over the period for which the Board is prepared to issue new licences. The Board accepts this to be reasonable in light of the likelihood that the full authorized quantities will not be exported due to the current over-supply situation and other market uncertainties in the United States and the quantity of uncommitted gas which will be available to new licence holders.

The Board's decision recognizes that the Northeast United States offers an attractive new market for Canadian gas. This must be balanced, however, against the distance the gas has to be transported and the cost to Canadians if significantly more pipeline facilities were to be constructed in Canada than would be necessary to serve growing domestic requirements upon expiry of the export licences. As a result, the Board has concluded that it would only be in Canada's interest to export approximately one-half of the volumes which were applied for to serve the Northeast United States.

The exports, by licence, which the Board is prepared to approve in light of the foregoing considerations are illustrated in Table 5-2.

The Board notes that a number of Applicants sought special licence conditions in the form of operating tolerances and one year make-up periods. Others included requests for annual averaging, that is, the making up in subsequent years of underdeliveries in preceding years. In this regard the Board refers to its Phase I Decision on the Review Phase issued in May 1982 which stated that the Board would consider each application on its own merit having consideration for the need and benefits of including these provisions in the licences. Accordingly, the Board's Decision in this regard is contained in the disposition of each separate application. In all cases, however, make-up conditions and tolerances will be subject to the availability of deliverability and pipeline capacity.

The Board has examined in detail the various sales contracts filed in support of each application. The Board is prepared to accept the contracts as filed.

The Board notes that before most of the new exports can commence, the Applicants will have to obtain United States import approvals and removal permits from producing provinces. They will also have to finalize contractual and financial arrangements, and obtain certificate and tariff and toll approvals from the NEB. Accordingly, the Board believes it prudent to include a sunset provision in all of the new export authorizations which would require that a new licence-holder have all the required arrangements and approvals in place, in a manner satisfactory to the Board, prior to 31 January 1984 or such later date as may be approved by the Board.

In light of the new licences which it is prepared to issue, the Board has recalculated its estimate of remaining surplus. Table 5-3 shows that the new exports of 12.2 EJ, plus an allowance of 1.7 EJ for fuel and reprocessing shrinkage, are some 4.5 EJ less than the surplus of 18.4 EJ judged to be available under the Reserves Formula.

Table 5-3

SURPLUS REMAINING AFTER

ALLOWANCE FOR NEW LICENCES

	Exajoules
Reserves Formula Surplus	18.4
Less New Export Approvals	12.2
Less Fuel and Shrinkage	1.7
Remaining Surplus	4.5

The Board has also recalculated the Deliverability Appraisal including the additional annual quantities approved for export. The results are illustrated in Figure 5-1 and shown numerically in Table 5-4. The Board has concluded that the deliverability not used in the early years should be adequate, when rolled forward, to meet Canadian requirements plus existing and new exports through to the year 2000.

The following sections set out the Board's decision in regard to each application. These serve as an informational summary only and do not constitute the authorized licence form. The detailed terms and conditions of each licence will be issued at a later date.

Table 5-2

NATURAL GAS EXPORTS
ARISING FROM DECISION
CALENDAR YEAR QUANTITIES
(Petajoules)

Export Company	Exit Point	Import Company	GHV (MJ/m^3)	1983	1984	1985	1986	1987	1988	1989	1990	1991	1992	1993	1994	1995	1996	1997	1998	1999	2000	Total
A&S	Kingsgate	Pacific Gas Transmission	38.33			6	61	190	240	253	303	198	99									1 350
Canadian Montana	Aden/Cardston	Montana Power	36.06/38.33			3	7	11	14	14	13	9	4									75
	Niagara Falls	Tennessee	37.63				1	7	6	6	9	6	3									38
Columbia	Monchy	Texas Gas	37.63	3	4	9	13	16	19	19	18	12	5									118
Consolidated	Emerson	Northern Natural	37.63		2	10	12	18	26	22												90
	Monchy	Northern Natural	37.63		2	10	12	18	26	22												90
Dome(1)	Grassy Point	Chubu, Chugoku, Kyushu, Osaka, Toho	38.20				85	130	150	159	167	167	167	167	167	167	167	167	167	167	167	2 403
KannGaz	Niagara Falls	Tennessee	37.63		8	49	49	49	48	49	49	48	49	47	34	22	10					511
Niagara Gas	Cornwall	St. Lawrence Gas	37.63					5	10	10	10	6	3									44
Pan-Alberta(2)	Monchy	Northwest Alaskan	37.63				28	74	225	312	295	190	87									1 211
	Kingsgate	Northwest Alaskan	38.33					16	95	95	90	58	27									381
	Niagara Falls	Algonquin, Texas Eastern, Transco	37.63		10	60	59	60	59	60	59	60	59	57	42	27	13					625
ProGas	Monchy	(Texas Eastern, Michigan Wisconsin,	37.63		2	9	11	13	13	6												54
	Emerson	Natural Gas, Tennessee)	37.63		3	21	25	29	30	13												121
	Emerson	Texas Gas	37.63	12	72	73	72	73	72	73	72	73	69	51	33	15						760
	Niagara Falls	Texas Eastern	37.63		3	20	19	20	19	20	19	20	19	19	14	9	4					205
Sulpetro	Niagara Falls	Transco	37.63	5	29	29	29	28	22	17	11	5										175
TransCanada	Emerson	Natural	37.63		7	39	39	39	39	39	39	39	39	37	28	18	8					410
	Emerson	Michigan Wisconsin	37.63		7	39	39	39	39	39	39	39	39	37	28	18	8					410
	Emerson	Midwestern	37.63		3	29	75	79	79	79	74	48	22									488
	Niagara Falls	Tennessee	37.63		7	39	39	39	39	39	39	39	39	37	24							380
	Niagara Falls	Tennessee	37.63		3	19	20	19	20	19	20	19	20	19	12							190
	Niagara Falls	Boundary	37.63		6	36	36	36	36	36	36	36	36	35	23							352
	Niagara Falls	Transco	37.63		10	58	59	58	59	58	59	58	59	56	41	27	12					614
	Niagara Falls	Texas Eastern	37.63			3	19	20	19	20	19	20	19	20	19	14	9	4				205
WTCL	Huntingdon/Kings.	Northwest Pipeline	39.10	2	2	2	2	2	2	48	272	212	150	86	55	25						860
	Monchy	Texas Gas	37.63	1	2	2	2	2	2	5	19	19	16									70
Total New Export Approvals(3)				23	182	565	813	1 090	1 408	1 532	1 731	1 381	1 030	668	520	342	231	171	167	167	167	12 230

(1) Dome total includes 42 PJ for period 1 January 2001 to 31 March 2001.

(2) For 1987 and 1988 the totals above do not include quantities reflecting the transformation of the conditional quantities to firm quantities. These figures are included in Table 3.12 Allowance Given for Natural Gas Export Licences.

(3) The total does not include Union Gas' approval for SNG exports nor the Transco approval. Union Gas has been authorized to export an additional term quantity of 64.1 PJ at a maximum annual level of 10.7 PJ. The Transco approval was for a licence to import for re-export.

Table 5-4

COMPARISON OF DELIVERABILITY AVAILABLE FOR NEW EXPORTS
WITH APPLIED-FOR AND APPROVED EXPORTS
(Petajoules)

	Gross Deliverability Available for New Exports (1)	Net Deliverability Available for New Exports (2)	Total Applied-For Quantities	Potential Approvals	Approved Exports
1982	1 930	1 693	4	4	-
1983	1 973	1 731	43	43	25
1984	1 896	1 663	319	319	182
1985	1 748	1 534	829	829	565
1986	1 770	1 553	1 106	1 106	813
1987	1 893	1 661	1 410	1 410	1 090
1988	2 044	1 793	1 734	1 734	1 408
1989	1 894	1 661	1 855	1 661	1 532
1990	1 977	1 733	2 117	1 733	1 731
1991	1 763	1 546	2 117	1 546	1 381
1992	1 482	1 299	2 140	1 299	1 030
1993	1 164	1 020	2 100	1 020	668
1994	895	784	1 981	784	520
1995	641	561	1 559	561	342
1996	403	353	1 530	353	231
1997	194	169	1 521	169	171
1998	-	-	1 459	-	167
1999	-	-	1 217	-	167
2000	-	-	680	-	167
	23 667	20 754	25 721 (3)	14 571	12 230 (4)

(1) Deliverability from established reserves and reserves additions less Canadian requirements including fuel and reprocessing shrinkage and exports under existing licences (See Table 3-14).

(2) The net deliverability available for new exports takes account of quantities required for reprocessing shrinkage and fuel used to transmit the exports to the Canada/U.S. border.

(3) An additional 820 PJ has been applied for beyond 2000 for a total of 25 721 + 820 = 26 541 PJ.

(4) Includes 42 PJ approved for export by Dome in the period January-March 2001.

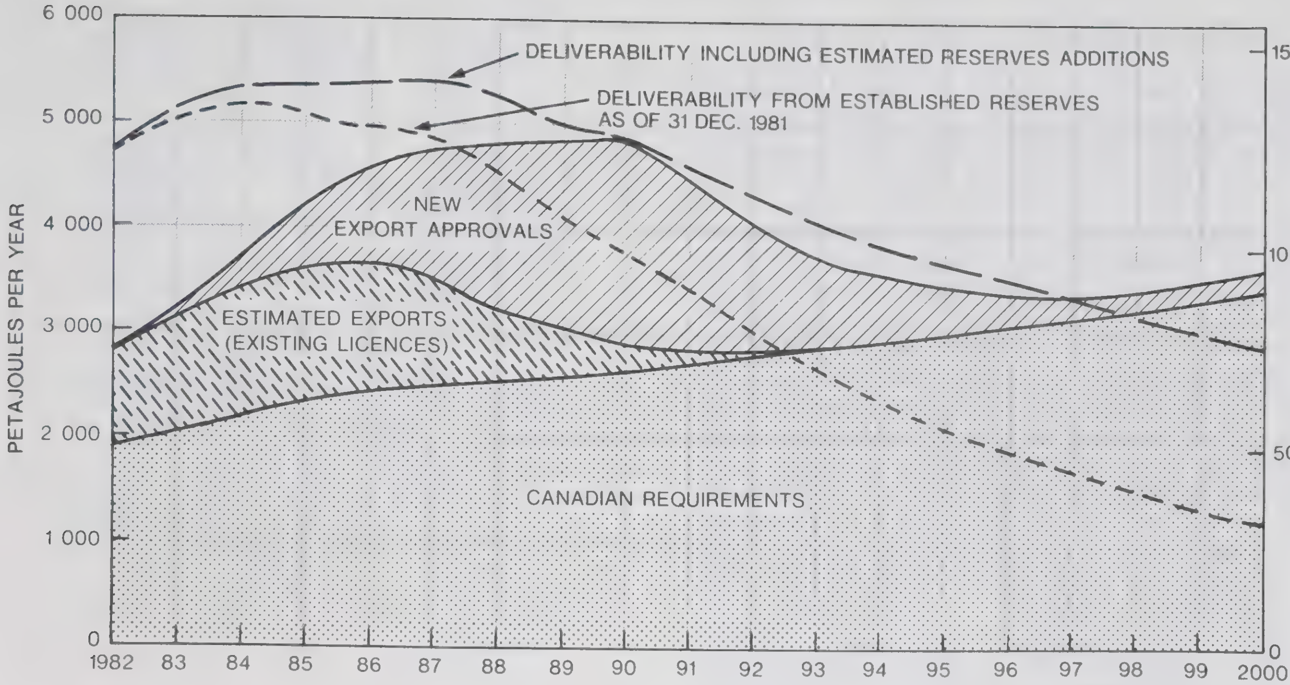


Figure 5-1 Deliverability Appraisal Showing Effect of New Export Approvals

5.2 Alberta and Southern

Alberta and Southern applied to amend Licences GL-24 and GL-35, to extend Licences GL-16 and GL-35 and for four new licences to replace existing Licences GL-3, GL-16, GL-24 and GL-35.

Having regard to the Board's findings on surplus and to its decision to permit exports at reduced levels in the last two years of licence extensions to 31 October 1992, the Board is not prepared to approve the term of the licences or the quantities requested by Alberta and Southern. However, the Board is prepared to issue orders amending Licences GL-24 and GL-35 and to issue new licences to replace Licences GL-3, GL-16 and GL-35 for export at Kingsgate, British Columbia as follows:

(a) to amend Licence GL-24 to provide for the following:

(i) the increase of the maximum daily and annual quantities in the licence for the period 1 November 1991 to 31 October 1992 to:

Period	Daily (10^3m^3)	Annual (10^6m^3)
1 Nov.'91 to 31 Oct.'92	4 784.6	1 577.4

(ii) an increase in the total term quantity to 52 491.0 x 10^6m^3.

(b) to amend Licence GL-35 to provide for the following:

(i) the increase of the maximum daily and annual quantities in the licence to:

Period	Daily (10^3m^3)	Annual (10^6m^3)
1 Nov.'85 to 31 Oct.'86	5 807.2	1 912.1
1 Nov.'86 to 31 Oct.'87	5 807.2	1 912.1

(ii) an increase in the total term quantity to 32 506.2 x 10^6m^3.

(c) to issue a new licence to replace existing Licence GL-3 commencing 1 November 1986 providing for the export of gas at Kingsgate, British Columbia under the following conditions:

(i)

Period	Daily (10^3m^3)	Annual (10^6m^3)
1 Nov.'86 to 31 Oct.'87	12 995.4	3 256.3
1 Nov.'87 to 31 Oct.'90	12 995.4	4 341.8
1 Nov.'90 to 31 Oct.'91	8 654.9	2 891.6
1 Nov.'91 to 31 Oct.'92	4 327.5	1 445.8

(ii) a total quantity that may be exported during the term of the licence of 20 619.1 x 10^6m^3.

(iii) a provision limiting the daily quantity of gas that may be exported during the period 31 October 1986 to 31 October 1987 to the difference between 12 995.4 x 10^3m^3 and that actually exported under Licence GL-3 in any one day.

(iv) a provision to permit annual averaging.

(d) to issue a new licence to replace existing Licence GL-16 commencing 1 November 1989 providing for the export of gas at Kingsgate, British Columbia under the following conditions:

(i)

Period	Daily (10^3m^3)	Annual (10^6m^3)
1 Nov.'89 to 31 Oct.'90	6 409.2	2 119.8
1 Nov.'90 to 31 Oct.'91	4 268.5	1 411.8
1 Nov.'91 to 31 Oct.'92	2 134.3	705.9

(ii) a total quantity that may be exported during the term of the licence of 4 237.5 x 10^6m^3.

(iii) a provision to permit annual averaging.

(e) to issue a new licence to replace existing Licence GL-35 commencing 1 November 1987 providing for the export of gas at Kingsgate, British Columbia under the following conditions:

(i)

Period	Daily (10^3m^3)	Annual (10^6m^3)
1 Nov.'87 to 31 Oct. '90	5 807.2	1 912.1
1 Nov.'90 to 31 Oct.'91	3 867.6	1 273.4
1 Nov.'91 to 31 Oct.'92	1 933.8	636.7

(ii) a total quantity that may be exported during the term of the licence of 7 646.4 x 10^6m^3.

(iii) a provision to permit annual averaging.

5.3 Canadian-Montana

Canadian-Montana applied to amend its existing Licences GL-25, GL-36 and GL-52 during the remaining licence terms ending 31 October 1993, 31 October 1987 and 31 December 1987 respectively. As well, it applied to extend the terms of Licences GL-17, GL-36 and GL-52 beyond their current expiry dates and for four new licences that would succeed Licences GL-5, GL-17, GL-25 and GL-36.

Having regard to its findings on surplus and to its decision to permit exports at reduced levels in the last two years of licence extensions to 31 October 1992 as well as to its decision to allocate 50 percent of the applied-for quantities to some exporters to the United States Northeast market, the Board is not prepared to approve the term or the quantities of the licences requested by Canadian-Montana. However, the Board is prepared to issue orders to amend Licences GL-25, GL-36 and GL-52 and to issue new licences to replace GL-5 and GL-17 commencing 1 November 1986 and 1 November 1989 respectively for export at Niagara Falls, Ontario. The Board is also prepared to issue a new licence to replace GL-52 commencing 1 January 1988 for export at Aden, Alberta and a new licence to replace GL-36 commencing 1 November 1987 for export at Cardston, Alberta as follows:

(a) to amend Licence GL-25 to provide for the following:

(i) the increase of the daily and annual quantities in the licence for the period commencing 1 November 1991 to 31 October 1992 to:

Period	Daily (10^3m^3)	Annual (10^6m^3)
1 Nov. '91 to 31 Oct. '92	439.0	133.6

(ii) an increase in the total term quantity to 4 905.4 x 10^6m^3.

(b) to amend Licence GL-36 to provide for the following:

(i) the increase of the daily and annual quantities in the licence for the period 1 November 1985 to 31 October 1987 to:

Period	Daily (10^3m^3)	Annual (10^6m^3)
1 Nov. '85 to 31 Oct. '86	339.9	103.4
1 Nov. '86 to 31 Oct. '87	339.9	103.4

(ii) an increase in the total term quantity to 1 757.7 x 10^6m^3.

(c) to amend Licence GL-52 to provide for the following:

(i) the decrease of the daily quantity for the period 1 January 1983 to 31 December 1984 and the increase of the daily and annual quantities in the licence for the period 1 January 1985 to 31 December 1987 to:

Period	Daily (10^3m^3)	Annual (10^6m^3)
1 Jan.'83 to 31 Dec.'84	1 133.1	283.3
1 Jan.'85 to 31 Dec.'85	1 133.1	283.3
1 Jan.'86 to 31 Dec.'86	1 133.1	283.3
1 Jan. '87 to 31 Dec.'87	1 133.1	283.3

(ii) an increase in the total term quantity to 2 266.4 x 10^6m^3.

(d) to issue a new licence to replace Licence GL-5 commencing 1 November 1986 providing for the export of gas at Niagara Falls, Ontario under the following conditions:

(i)

Period	Daily (10^3m^3)	Annual (10^6m^3)
1 Nov. '86 to 31 Oct. '87	637.4	193.9
1 Nov. '87 to 31 Oct. '90	509.9	155.1
1 Nov. '90 to 31 Oct. '91	339.6	103.3
1 Nov. '91 to 31 Oct. '92	169.8	51.6

(ii) a total quantity that may be exported during the term of the licence of 814.1 x 10^6m^3.

(iii) a provision to allow annual averaging.

(e) to issue a new licence to replace Licence GL-17 commencing 1 November 1989 providing for the export of gas at Niagara Falls, Ontario under the following conditions:

(i)

Period	Daily (10^3m^3)	Annual (10^6m^3)
1 Nov. '89 to 31 Oct. '90	340.0	103.4
1 Nov. '90 to 31 Oct. '91	226.4	68.9
1 Nov. '91 to 31 Oct. '92	113.2	34.4

(ii) a total quantity that may be exported during the term of the licence of 206.7 x 10^6m^3.

(iii) a provision to allow annual averaging.

(f) to issue a new licence to replace Licence GL-52 commencing 1 January 1988 providing for the export of gas at Aden, Alberta under the following conditions:

(i)

Period	Daily (10^3m^3)	Annual (10^6m^3)
1 Jan. '88 to 31 Oct. '88	1 133.1	236.1
1 Nov. '88 to 31 Oct. '90	1 133.1	283.3
1 Nov. '90 to 31 Oct. '91	754.6	188.7
1 Nov. '91 to 31 Oct. '92	377.3	94.3

(ii) a total quantity that may be exported during the term of the licence of 1 085.7 x 10^6m^3.

(iii) a provision to allow annual averaging.

(g) to issue a new licence to replace Licence GL-36 commencing 1 November 1987 providing for the export of gas at Cardston, Alberta under the following conditions:

(i)

Period	Daily (10^3m^3)	Annual (10^6m^3)
1 Nov. '87 to 31 Oct. '90	339.9	103.4
1 Nov. '90 to 31 Oct. '91	226.4	68.9
1 Nov. '91 to 31 Oct. '92	113.2	34.4

(ii) a total quantity that may be exported during the term of the licence of 413.5 x 10^6m^3.

(iii) a provision to allow annual averaging.

5.4 Columbia

Columbia applied to amend and extend Licence GL-54 to 31 October 1997.

Having regard to the Board's findings on surplus and to its decision to permit exports at reduced levels in the last two years of licence extensions to 31 October 1992, the Board is not prepared to approve the licence term or the quantities requested by Columbia. However, the Board is prepared to issue an order amending Licence GL-54 and to issue a new licence to replace Licence GL-54 commencing 1 January 1988 for the export of gas at Monchy, Saskatchewan as follows:

(a) to amend Licence GL-54 to provide for the following:

(i) the increase of the maximum daily and annual quantities in the Licence for the period 1 April 1983 to 31 December 1987 to:

Period	Daily (10^3m^3)	Annual (10^6m^3)
1 Apr. '83 to 31 Dec. '83	1 450.0	387.7
1 Jan. '84 to 31 Dec. '84	1 450.0	517.0
1 Jan. '85 to 31 Dec. '85	1 450.0	517.0
1 Jan. '86 to 31 Dec. '86	1 450.0	517.0
1 Jan. '87 to 31 Dec. '87	1 450.0	517.0

(ii) an increase in the total term quantity to 3 556.1 x 10^6m^3.

(iii) a provision to permit annual averaging.

(b) to issue a new licence to replace Licence GL-54 commencing 1 January 1988 providing for the export of gas at Monchy, Saskatchewan under the following conditions:

(i)

Period	Daily (10^3m^3)	Annual (10^6m^3)
1 Jan. '88 to 31 Oct. '88	1 450.0	430.8
1 Nov. '88 to 31 Oct. '90	1 450.0	517.0
1 Nov. '90 to 31 Oct. '91	965.7	344.3
1 Nov. '91 to 31 Oct. '92	482.8	172.2

(ii) a total quantity that may be exported during the term of the licence of 1 981.3 x 10^6m^3.

(iii) a provision to permit annual averaging.

(iv) a daily tolerance of two percent to accommodate temporary operating conditions.

5.5 Consolidated

Consolidated applied to amend and extend Licence GL-61 to 31 October 1989.

Having regard to the Board's findings on surplus, the Board is prepared to issue an order to amend Licence GL-61 and to issue a new licence to replace GL-61 commencing 1 November 1987 for the export of gas at Monchy, Saskatchewan and Emerson, Manitoba as follows:

(a) to amend Licence GL-61 to provide for the following:

(i) the increase of the maximum daily and annual quantities in the licence for the period 1 November 1984 to 31 October 1987 to:

Period	Daily (10^3m^3)	Annual (10^6m^3)
1 Nov. '84 to 31 Oct. '85	5 665.6	2 068.0
1 Nov. '85 to 31 Oct. '86	4 532.5	1 654.0
1 Nov. '86 to 31 Oct. '87	3 824.3	1 396.0

(ii) an increase in the total term quantity to 13 389.6 x 10^6m^3.

(iii) a provision allowing for the export of up to 50 percent of the incremental daily and annual quantities at Monchy, Saskatchewan.

(b) to issue a new licence to replace Licence GL-61 commencing 1 November 1987 providing for the export of gas at Monchy, Saskatchewan and Emerson, Manitoba under the following conditions:

(i)

Period	Daily (10^3m^3)	Annual (10^6m^3)
1 Nov. '87 to 31 Oct. '89	3 824.3	1 396.0

(ii) a total quantity that may be exported during the term of the licence of 2 792.0 x 10^6m^3.

(iii) a provision limiting the exports at Monchy, Saskatchewan to 50 percent of the maximum daily and annual quantities.

5.6 Dome

Dome applied for a new licence to export LNG to Japan for a period of 19 years and six months commencing 1 April 1986.

Having regard to the Board's findings on surplus, the Board is not prepared to approve the licence term or the quantities requested by Dome. It was felt that the Western LNG Project warranted special consideration due to the large expenditures on the pipeline and liquefaction plant in Canada, and on the regasification, storage, and other facilities in Japan. In the light of these and other considerations outlined above, the Board is prepared to issue a new licence for the export of gas at Grassy Point, British Columbia for a 15-year period commencing 1 April 1986 under the following conditions:

(i)

Period	Annual (10^6m^3)
1 Apr. '86 to 31 Dec. '86	2 258.0
1 Jan. '87 to 31 Dec. '87	3 309.0
1 Jan. '88 to 31 Dec. '88	3 986.0
1 Jan. '89 to 31 Dec. '89	4 136.0
1 Jan. '90 to 31 Dec. 2000	4 362.0
1 Jan. 2001 to 31 Mar. 2001	1 090.0

(ii) a total quantity that may be exported during the term of the licence of 62 761.0 x 10^6m^3.

(iii) an annual tolerance of 10 percent to accommodate temporary operating conditions.

(iv) This licence shall come into force upon the performance of the following conditions:

1) the following must be filed with the Board by 31 January 1984 or such later date as, upon application, the Board may specify:

a) certified copies of removal permits in respect of Dome's gas supply located in Alberta and British Columbia;

b) proof of final regulatory approvals pursuant to the Foreign Investment Review Act;

c) a certified copy of the approval of the Export-Import Bank of Japan;

d) certificates of public convenience and necessity from the NEB issued,

i) in respect of the LNG Plant;

ii) in respect of the pipeline from the Alberta border to the LNG Plant.

e) orders issued by the NEB under Section 50 of the NEB Act approving the form, content and other aspects of the Dome and Westcoast tariffs resulting from a hearing under Part IV dealing with, inter alia,

i) method of regulation;

ii) rate base matters including AFUDC and working capital;

iii) cost of service matters including tariff levelling;

iv) rate of return on rate base matters;

v) income tax matters.

2) the following must be filed with and approved by the Board by 31 January 1984 or such later date as, upon application, the Board may specify:

a) a copy of the executed gas supply agreement between Dome and the British Columbia Petroleum Corporation;

b) a copy of an executed transportation agreement between Dome and Westcoast

governing the transportation of the gas from the Alberta border to the LNG Plant;

c) a certified copy of the executed loan agreement;

d) certified copies of the executed shipping contracts;

(v) all amendments or changes to the contracts and agreements filed at the Hearing or later filed in accordance with the conditions to this licence, shall be filed with the Board.

(vi) Dome shall not export or permit or cause to be exported LNG pursuant to or in conformity with any amendment, change, side letter or other agreement corollary to:

(1) the LNG Sales Agreement dated 20 March 1982 and side letters as filed with the Board at the Hearing;

(2) the LNG FOB Sales Agreement dated 24 September 1982 as filed with the Board at the Hearing;

unless such amendment, change, side letter or other agreement corollary to the aforementioned Agreements have been approved by the Board.

(vii) the price to be paid at the international boundary for the export of LNG shall be the "Contract Sales Price" as defined in Article X of the LNG Sales Agreement dated 20 March 1982 less such costs, fees and charges including but not limited to the "Transportation Element", "Insurance Element" and the "Management and Administrative Charge" as described in Article X of the LNG FOB Sales Agreement dated 24 September 1982, as may be approved by the Board from time to time.

(viii) Dome shall provide to the Board all information requested by the Board relating to the Western LNG Project, including, without restricting the generality of the foregoing, all information as may be requested relating to shipping and insurance costs and management and administrative charges.

(ix) a make-up provision to permit the delivery of quantities not taken during the term of the licence.

5.7 KannGaz

KannGaz applied for a new licence to export 19 381.5 x $10^6 m^3$ over a 15-year term at Niagara Falls, Ontario.

Having regard to its findings on surplus and to its decision to allow exports at reduced levels during the last three years of new licences requiring the construction of new pipeline facilities, the Board is not prepared to approve the term of the licence or the quantities requested by KannGaz. However, the Board is prepared to issue a licence as follows:

a new licence for the export of gas at Niagara Falls, Ontario for a twelve-year period commencing 1 November 1984, providing for the export of gas under the following conditions:

(i)

Period	Daily ($10^3 m^3$)	Annual ($10^6 m^3$)
1 Nov. '84 to 31 Oct. '93	3 540.0	1 292.1
1 Nov. '93 to 31 Oct. '94	2 655.0	969.1
1 Nov. '94 to 31 Oct. '95	1 770.0	646.0
1 Nov. '95 to 31 Oct. '96	885.0	323.0

(ii) a total quantity that may be exported during the term of the licence of 13 567.0 x $10^6 m^3$.

(iii) a daily tolerance of 10 percent to accommodate temporary operating conditions.

(iv) during the period 1 November 1996 to 31 October 1997, a make-up provision up to the maximum daily quantity of 3 540.0 x $10^3 m^3$, subject to the availability of capacity and deliverability, to permit recovery of quantities of gas paid for but not taken under the terms of the sales contract or 1 292.1 x $10^6 m^3$ whichever is less.

5.8 Niagara Gas

Niagara Gas applied to combine the existing authorized licence quantities under Licences GL-6 and GL-55 into one licence, GL-55, and to extend the term of the revised single licence to 31 October 1995. Niagara Gas indicated that it would consent to a revocation of Licence GL-6 provided that its application were approved.

Having regard to the Board's findings on surplus and to its decision to permit exports at reduced levels in the last two years of licence extensions to 31 October 1992, the Board is not prepared to approve the licence term or the quantities requested by Niagara Gas. However, the Board is prepared to issue an order amending Licence GL-55 and to issue a new licence to replace Licence GL-55 commencing 1 November 1987 for the export of gas at Cornwall, Ontario as follows:

(a) to amend Licence GL-55 to provide for the following:

(i) the increase of the maximum daily and annual quantities in the licence for the period 1 April 1983 to 31 October 1987 to:

Period	Daily ($10^3 m^3$)	Annual ($10^6 m^3$)
1 Apr. '83 to 31 Oct. '83	1 200.0	145.8
1 Nov. '83 to 31 Oct. '85	1 200.0	250.0
1 Nov. '85 to 31 Oct. '87	1 200.0	275.0

(ii) an increase in the total term quantity to 1 500.2 x $10^6 m^3$.

(iii) this amendment will take effect upon the revocation of Licence GL-6.

(b) to issue a new licence to replace Licence GL-55 commencing 1 November 1987 providing for the export of gas at Cornwall, Ontario under the following conditions:

Period	Daily ($10^3 m^3$)	Annual ($10^6 m^3$)
1 Nov. '87 to 31 Oct. '90	1 200.0	275.0
1 Nov. '90 to 31 Oct. '91	799.2	183.1
1 Nov. '91 to 31 Oct. '92	399.2	91.6

(ii) a total quantity that may be exported during the term of the licence of $1\ 099.7 \times 10^6 m^3$.

(iii) a daily tolerance of 10 percent to accommodate temporary operating conditions.

5.9 Ocelot

Ocelot applied for a licence to export gas produced in the Province of Saskatchewan for a 16-year period.

For reasons given earlier in Chapter 4, the Board is not prepared to issue a licence to Ocelot for the export of Saskatchewan gas at this time.

5.10 Pan-Alberta

Pan-Alberta filed two applications with the Board. One sought to amend and extend existing Licences GL-58 and GL-59 and to amend Licence GL-63. The other application sought approval for a new licence to export gas at Niagara Falls, Ontario commencing 1 November 1984.

With respect to its first application, the Board, having regard to its findings on surplus and to its decision to permit exports at reduced levels in the last two years of licence extensions to 31 October 1992, is not prepared to approve the licence terms or the quantities requested by Pan-Alberta. However, the Board is prepared to issue an order amending Licences GL-58, GL-59 and GL-63 and to issue new licences to replace Licences GL-58 and GL-59 commencing 1 November 1988 for the export of gas at Monchy, Saskatchewan (GL-58) and at Kingsgate, British Columbia (GL-59) as follows:

(a) to amend Licence GL-58 to provide for the following:

(i) the increase of the maximum daily and annual quantities in the licence for the period 1 November 1986 to 31 October 1988. This amendment converts the quantities currently authorized for export on a conditional basis into firm exports as set forth below:

Period	Daily (10^3m^3)	Annual (10^6m^3)
1 Nov. '86 to 31 Oct. '87	19 837.2	6 600.4
1 Nov. '87 to 31 Oct. '88	24 928.5	8 294.4

(ii) an increase in the total term quantity to 50 146.0 x 10^6m^3.

(b) to issue a new licence to replace Licence GL-58 commencing 1 November 1988 providing for the export of gas at Monchy, Saskatchewan under the following conditions:

(i)

Period	Daily (10^3m^3)	Annual (10^6m^3)
1 Nov. '88 to 31 Oct. '90	24 928.5	8 294.4
1 Nov. '90 to 31 Oct. '91	16 602.4	5 524.1
1 Nov. '91 to 31 Oct. '92	8 301.2	2 762.0

(ii) a total quantity that may be exported during the term of the licence of 24 874.9 x 10^6m^3.

(c) to amend Licence GL-59 to provide for the following:

(i) the variation of the current daily and annual quantities by converting the quantities currently authorized for export on a conditional basis for the period 1 November 1987 to 31 October 1988 into firm exports as set out below:

(i)

Period	Daily (10^3m^3)	Annual (10^6m^3)
1 Nov. '87 to 31 Oct. '88	7 478.6	2 488.3

(ii) an increase in the total term quantity to 16 174.0 x 10^6m^3.

(d) to issue a new licence to replace Licence GL-59 commencing 1 November 1988 providing for the export of gas at Kingsgate, British Columbia under the following conditions:

(i)

Period	Daily (10^3m^3)	Annual (10^6m^3)
1 Nov. '88 to 31 Oct. '90	7 478.6	2 488.3
1 Nov. '90 to 31 Oct. '91	4 980.7	1 657.2
1 Nov. '91 to 31 Oct. '92	2 490.7	828.6

(ii) a total quantity that may be exported during the term of the licence of 7 462.4 x 10^6m^3.

(e) to amend Licence GL-63 to provide for the following:

(i) the reduction of the maximum daily

and annual quantities in the licence for the period 1 November 1984 to 31 October 1987, and the conversion of the quantities currently authorized for export on a conditional basis for the periods 1 November 1985 to 31 October 1986 and 1 November 1986 to 31 October 1987 into firm exports as set out below:

Period	Daily (10^3m^3)	Annual (10^6m^3)
1 Nov. '84 to 31 Oct. '85	1 869.7	622.1
1 Nov. '85 to 31 Oct. '86	3 739.4	1 244.1
1 Nov. '86 to 31 Oct. '87	5 609.6	1 866.2

(ii) a reduction in the total term quantity to 4 354.5 x 10^6m^3.

With respect to Pan-Alberta's second application for a new licence to export gas at Niagara Falls, Ontario the Board, having regard to its findings on surplus and to its decision to permit exports at reduced levels in the last three years of new licences requiring the construction of new pipeline facilities as well as to its decision to allocate 50 percent of the applied-for quantities to some exporters to the United States Northeast market, the Board is not prepared to approve either the term of the licence or the quantities requested by Pan-Alberta. However, the Board is prepared to issue a new licence to Pan-Alberta commencing 1 November 1984 for the export of gas at Niagara Falls, Ontario as follows:

(i)

Period	Daily (10^3m^3)	Annual (10^6m^3)
1 Nov. '84 to 31 Oct. '93	4 332.5	1 581.4
1 Nov. '93 to 31 Oct. '94	3 249.4	1 186.0
1 Nov. '94 to 31 Oct. '95	2 166.2	790.7
1 Nov. '95 to 31 Oct. '96	1 083.1	395.4

(ii) a total quantity that may be exported during the term of the licence of 16 604.7 x 10^6m^3.

(iii) a daily tolerance of two percent to accommodate temporary operating conditions.

5.11 ProGas

ProGas applied for an amendment and extension to its existing Licence GL-56 and for a new licence to export gas at Emerson, Manitoba, Niagara Falls, Ontario and at Kingsgate, British Columbia commencing 1 November 1983.

With regard to ProGas' application for an amendment and extension to GL-56, the Board, having regard to its findings on surplus is prepared to issue an order amending Licence GL-56 and to issue a new licence to replace Licence GL-56 commencing 1 November 1987 for the export of gas at Monchy, Saskatchewan and Emerson, Manitoba as follows:

(a) to amend Licence GL-56 to provide for the following:

the increase of the maximum daily and annual quantities in the licence for the period 1 November 1984 to 31 October 1987 to:

(i)

Period	Daily (10^3m^3)	Annual (10^6m^3)
1 Nov. '84 to 31 Oct. '85	9 440.9	3 100.0
1 Nov. '85 to 31 Oct. '86	7 552.7	2 480.0
1 Nov. '86 to 31 Oct. '87	5 664.5	1 860.0

(ii) a provision limiting the maximum daily and annual quantities for export at Monchy, Saskatchewan.

(b) to issue a new licence to replace GL-56 commencing 1 November 1987 providing for the export of gas at Monchy, Saskatchewan and Emerson, Manitoba under the following conditions:

(i)

Period	Daily (10^3m^3)	Annual (10^6m^3)
1 Nov. '87 to 31 Oct. '88	3 776.4	1 240.0
1 Nov. '88 to 31 Oct. '89	1 888.2	620.0

(ii) a total quantity that may be exported during the term of the licence of 1 860.0 x 10^6m^3.

(iii) a provision limiting the maximum daily and annual quantities for export at Monchy, Saskatchewan.

With regard to ProGas' application for a new licence to export gas at Emerson, Manitoba, Niagara Falls, Ontario and Kingsgate, British Columbia the Board, having regard to its findings on surplus and to the Board's decision to permit exports at reduced levels in the last three years of new licences requiring construction of new pipeline facilities, is not prepared to approve the term of the licence or the quantities requested by ProGas. Furthermore, having regard to its decision to allocate to some exporters to the United States Northeast market 50 percent of the applied-for quantity, the Board is not prepared to approve the quantities requested for export at Niagara Falls, Ontario. Finally, for reasons outlined above, the Board is not prepared to authorize exports by ProGas at Kingsgate, British Columbia.

However, the Board is prepared to issue two new licences to ProGas as follows:

1. A new licence for the export of gas at Niagara Falls, Ontario for a 12-year period commencing 1 November 1984, providing for the export of gas under the following conditions:

(i)

Period	Daily (10^3m^3)	Annual (10^6m^3)
1 Nov. '84 to 31 Oct. '93	1 420.0	518.3
1 Nov. '93 to 31 Oct. '94	1 065.0	388.7
1 Nov. '94 to 31 Oct. '95	710.0	259.1
1 Nov. '95 to 31 Oct. '96	355.0	129.6

(ii) a total quantity that may be exported during the term of the licence of 5 442.1 x 10^6m^3.

(iii) during the period 1 November 1996 to 31 October 1997, a make-up provision up to the maximum daily quantity of 1 420.0 x 10^3m^3, subject to the availability of capacity and deliverability, to permit recovery of quantities of gas paid for but not taken under the terms of the sales contract or 518.3 x 10^6m^3 whichever is less.

(iv) a daily tolerance of two percent to accommodate temporary operating conditions.

2. A new licence for the export of gas at Emerson, Manitoba for a 12-year period commencing 1 November 1983, providing for the export of gas under the following conditions:

(i)

Period	Daily (10^3m^3)	Annual (10^6m^3)
1 Nov. '83 to 31 Oct. '92	5 270.0	1 923.5
1 Nov. '92 to 31 Oct. '93	3 952.5	1 442.6
1 Nov. '93 to 31 Oct. '94	2 635.0	961.7
1 Nov. '94 to 31 Oct. '95	1 317.5	480.9

(ii) a total quantity that may be exported during the term of the licence of 20 196.7 x 10^6m^3.

(iii) during the period 1 November 1995 to 31 October 1996, a make-up provision up to the maximum daily quantity of 5 270.0 x 10^3m^3, subject to the availability of capacity and deliverability, to permit recovery of quantities of gas paid for but not taken under the terms of the sales contract or 1 923.5 x 10^6m^3 whichever is less.

(iv) a daily tolerance of two percent to accommodate temporary operating conditions.

5.12 Sulpetro

Sulpetro applied for a new licence to succeed its existing Licence GL-57.

In view of the evidence, the Board's findings on surplus and for reasons given earlier, the Board is prepared to issue a new licence to Sulpetro. However, the Board is not prepared to approve the constant maximum daily quantity as applied for since this would result in low load factors in the later years of the licence. The Board is prepared to approve the following:

A new licence for the export of gas at Niagara Falls, Ontario for an eight-year period commencing 1 November 1983, providing for the export of gas under the following conditions:

(i)

Period	Daily (10^3m^3)	Annual (10^6m^3)
1 Nov. '83 to 31 Oct. '87	2 125.0	775.6
1 Nov. '87 to 31 Oct. '88	1 700.0	620.5
1 Nov. '88 to 31 Oct. '89	1 275.0	465.4
1 Nov. '89 to 31 Oct. '90	850.0	310.2
1 Nov. '90 to 31 Oct. '91	425.0	155.1

(ii) a total quantity that may be exported during the term of the licence of 4 653.7 x 10^6m^3.

(iii) a daily tolerance of 10 percent to accommodate temporary operating conditions.

5.13 TransCanada

TransCanada sought eight new licences as follows:

(a) Application for a new licence to export gas to Boundary Gas at Niagara Falls, Ontario for a ten-year period commencing 1 November 1984.

Having regard to the Board's findings on surplus and to its decision to permit exports at reduced levels in the tenth year of new licences requiring construction of new pipeline facilities and to the Board's decision to allocate to some exporters to the United States Northeast market 50 percent of the applied-for quantities, the Board is not prepared to approve the quantities requested by TransCanada. However, the Board is prepared to issue a new licence to TransCanada for a ten-year period commencing 1 November 1984 for the export of gas at Niagara Falls, Ontario as follows:

(i)

Period	Daily (10^3m^3)	Annual (10^6m^3)
1 Nov. '84 to 31 Oct. '93	2 620.3	959.0
1 Nov. '93 to 31 Oct. '94	1 965.2	719.2

(ii) a total quantity that may be exported during the term of the licence of 9 350.2 x 10^6m^3.

(iii) during the period 1 November 1994 to 31 October 1995, a make-up provision up to the maximum daily quantity of 2 620.3 x 10^3m^3, subject to the availability of capacity and deliverability, to permit recovery of quantities of gas paid for but not taken under the terms of the sales contract or 959.0 x 10^6m^3 whichever is less.

(iv) a daily tolerance of two percent to accommodate temporary operating conditions.

(b) Application for a new licence to export gas to Tennessee (Tennessee #1) at Niagara Falls, Ontario for a ten-year period commencing 1 November 1984.

Having regard to its findings on surplus and to its decision to permit exports at reduced levels in the tenth year of new licences requiring construction of new pipeline facilties and to its decision to allocate to some exporters to the United States

Northeast market 50 percent of the applied-for quantities, the Board is not prepared to approve the quantities requested by TransCanada. However, the Board is prepared to issue a new licence to TransCanada for a ten-year period commencing 1 November 1984 for the export of gas at Niagara Falls, Ontario as follows:

(i)

Period	Daily (10^3m^3)	Annual (10^6m^3)
1 Nov. '84 to 31 Oct. '93	1 416.4	518.4
1 Nov. '93 to 31 Oct. '94	1 062.3	388.8

(ii) a total quantity that may be exported during the term of the licence of 5 054.4 x 10^6m^3.

(iii) during the period 1 November 1994 to 31 October 1995, a make-up provision up to the maximum daily quantity of 1 416.4 x 10^3m^3, subject to the availability of capacity and deliverability, to permit recovery of quantities of gas paid for but not taken under the terms of the sales contract or 518.4 x 10^6m^3 whichever is less.

(iv) a daily tolerance of two percent to accommodate temporary operating conditions.

(c) Application for a new licence to export gas to Tennessee (Tennessee #2) at Niagara Falls, Ontario for a ten-year period commencing 1 November 1984.

Having regard to its findings on surplus and to its decision to permit exports at reduced levels in the tenth year of new licences requiring construction of new pipeline facilities and to its decision to allocate to some exporters to the United States Northeast market 50 percent of the applied-for quantities, the Board is not prepared to approve the quantities requested by TransCanada. However, the Board is prepared to issue a new licence to TransCanada for a 10-year period commencing 1 November 1984 for the export of gas at Niagara Falls, Ontario as follows:

(i)

Period	Daily (10^3m^3)	Annual (10^6m^3)
1 Nov. '84 to 31 Oct. '93	2 832.8	1 036.8
1 Nov. '93 to 31 Oct. '94	2 124.6	777.6

(ii) a total quantity that may be exported during the term of the licence of 10 108.8 x 10^6m^3.

(iii) during the period 1 November 1994 to 31 October 1995, a make-up provision up to the maximum daily quantity of 2 832.8 x 10^3m^3, subject to the availability of capacity and deliverability, to permit recovery of quantities of gas paid for but not taken under the terms of the sales contract or 1 036.8 x 10^6m^3 whichever is less.

(iv) a daily tolerance of two percent to accommodate temporary operating conditions.

(d) Application for a new licence to export gas to Natural Gas Pipeline at Emerson, Manitoba for a 15-year period commencing 1 November 1984.

Having regard to its findings on surplus and to its decision to permit exports at reduced levels in the last three years of new licences requiring construction of new pipeline facilities , the Board is not prepared to approve the licence term or the quantities requested by TransCanada. However, the Board is prepared to issue a new licence to TransCanada for a 12-year period commencing 1 November 1984 for the export of gas at Emerson, Manitoba as follows:

(i)

Period	Daily (10^3m^3)	Annual (10^6m^3)
1 Nov. '84 to 31 Oct. '93	2 832.8	1 036.8
1 Nov. '93 to 31 Oct. '94	2 124.6	777.6
1 Nov. '94 to 31 Oct. '95	1 416.4	518.4
1 Nov. '95 to 31 Oct. '96	708.2	259.2

(ii) a total quantity that may be exported during the term of the licence of 10 886.4 x 10^6m^3.

(iii) during the period 1 November 1996 to 31 October 1997, a make-up provision up to the maximum daily quantity of 2 832.8 x 10^3m^3, subject to the availability of capacity and deliverability, to permit recovery of quantities of gas paid for but not taken under the terms of the sales contract or 1 036.8 x 10^6m^3 whichever is less.

(iv) a daily tolerance of two percent to accommodate temporary operating conditions.

(e) Application for a new licence to export gas to Michigan-Wisconsin at Emerson, Manitoba for a 15-year period commencing 1 November 1984.

Having regard to its findings on surplus and to its decision to permit exports at reduced levels in the last three years of new licences requiring construction of new pipeline facilities, the Board is not prepared to approve the licence term or the quantities requested by TransCanada. However, the Board is prepared to issue a new licence to TransCanada for a 12-year period commencing 1 November 1984 for the export of gas at Emerson, Manitoba as follows:

(i)

Period	Daily (10^3m^3)	Annual (10^6m^3)
1 Nov. '84 to 31 Oct. '93	2 832.8	1 036.8
1 Nov. '93 to 31 Oct. '94	2 124.6	777.6
1 Nov. '94 to 31 Oct. '95	1 416.4	518.4
1 Nov. '95 to 31 Oct. '96	708.2	259.2

(ii) a total quantity that may be exported during the term of the licence of 10 886.4 x 10^6m^3.

(iii) during the period 1 November 1996 to 31 October 1997, a make-up provision up to the maximum daily quantity of 2 832.8 x 10^3m^3, subject to the availability of capacity and deliverability, to permit recovery of quantities of gas paid for but not taken under the terms of the sales contract or 1 036.8 x 10^6m^3 whichever is less.

(iv) a daily tolerance of two percent to accommodate temporary operating conditions.

(f) Application for a new licence to export gas to Transco at Emerson, Manitoba and/or Niagara Falls, Ontario for a 15-year period commencing 1 November 1984.

Having regard to its findings on surplus and to its decision to permit exports at reduced levels in the last three years of new licences requiring construction of new pipeline facilities as well as to its decision to allocate to some exporters to the United States Northeast market 50 percent of the applied-for quantities, the Board is not prepared to approve the licence term or the quantities requested by TransCanada. However, the Board is prepared to issue a new licence to TransCanada for a 12-year period commencing 1 November 1984 for the export of gas at Emerson, Manitoba and/or Niagara Falls, Ontario as follows:

(i)

Period	Daily (10^3m^3)	Annual (10^6m^3)
1 Nov. '84 to 31 Oct. '93	4 249.2	1 555.2
1 Nov. '93 to 31 Oct. '94	3 186.9	1 166.4
1 Nov. '94 to 31 Oct. '95	2 124.6	777.6
1 Nov. '95 to 31 Oct. '96	1 062.3	388.8

(ii) a total quantity that may be exported during the term of the licence of 16 329.6 x 10^6m^3.

(iii) during the period 1 November 1996 to 31 October 1997, a make-up provision up to the maximum daily quantity of 4 249.2 x 10^3m^3, subject to the availability of capacity and deliverability, to permit recovery of quantities of gas paid for but not taken under the terms of the sales contract or 1 555.2 x 10^6m^3 whichever is less.

(iv) a daily tolerance of two percent to accommodate temporary operating conditions.

(g) Application for a new licence to export gas to Midwestern Gas at Emerson, Manitoba for a 15-year period commencing 1 November 1984. The new licence would replace TransCanada's existing Licence GL-60.

Having regard to its findings on surplus and to its decision to permit exports at reduced levels in the last two years of licence extensions to 31 October 1992, the Board is not prepared to approve the licence term or the quantities requested by TransCanada. However, the Board is prepared to issue a new licence to replace Licence GL-60 for a period commencing 1 November 1984 for the export of gas at Emerson, Manitoba as follows:

(i)

Period	Daily $(10^3 m^3)$	Annual $(10^6 m^3)$
1 Nov. '84 to 31 Oct. '85	6 317.1	524.1
1 Nov. '85 to 31 Oct. '86	6 317.1	1 957.3
1 Nov. '86 to 31 Oct. '90	6 317.1	2 096.3
1 Nov. '90 to 31 Oct. '91	4 207.2	1 396.1
1 Nov. '91 to 31 Oct. '92	2 103.6	698.1

(ii) a total quantity that may be exported during the term of the licence of 12 960.8 x $10^6 m^3$.

(iii) during the period 1 November 1992 to 31 October 1993, a make-up provision up to the maximum daily quantity of 6 317.1 x $10^3 m^3$, subject to the availability of capacity and deliverability, to permit recovery of quantities of gas paid for but not taken under the terms of the sales contract or 2 096.3 x $10^6 m^3$ whichever is less.

(iv) a provision limiting the total quantity of gas that may be exported during the period 1 November 1984 to 14 December 1985 to the difference between 6 317.1 x $10^3 m^3$ and the quantity actually exported under Licence GL-60 in any one day.

(v) a daily tolerance of two percent to accommodate temporary operating conditions.

(h) Application for a new licence to export gas to Texas Eastern at Niagara Falls, Ontario for a 14-year period commencing 1 November 1985.

Having regard to its findings on surplus and to its decision to permit exports at reduced levels in the last three years of new licences requiring construction of new pipeline facilities as well as to its decision to allocate to some exporters to the United States Northeast market 50 percent of the applied-for quantities, the Board is not prepared to approve the licence term or the quantities requested by TransCanada. However, the Board is prepared to issue a new licence to TransCanada for a 12-year period commencing 1 November 1985 for the export of gas at Niagara Falls, Ontario as follows:

(i)

Period	Daily $(10^3 m^3)$	Annual $(10^6 m^3)$
1 Nov. '85 to 31 Oct. '94	1 416.4	518.4
1 Nov. '94 to 31 Oct. '95	1 062.3	388.8
1 Nov. '95 to 31 Oct. '96	708.2	259.2
1 Nov. '96 to 31 Oct. '97	354.1	129.6

(ii) a total quantity that may be exported during the term of the licence of 5 443.2 x $10^6 m^3$.

(iii) during the period 1 November 1997 to 31 October 1998, a make-up provision up to the maximum daily quantity of 1 416.4 x $10^3 m^3$, subject to the availability of capacity and deliverability, to permit recovery of quantities of gas paid for but not taken under the terms of the sales contract or 518.4 x $10^6 m^3$ whichever is less.

(iv) a daily tolerance of two percent to accommodate temporary operating conditions.

5.14 Transco

Transco applied for a new licence to import gas at Sarnia, Ontario for re-export at Niagara Falls, Ontario for a 20-year period commencing 1 November 1984.

Having regard to its decision to permit exports at reduced levels in the last three years of new licences requiring construction of new pipeline facilities as well as its decision to allocate to some exporters to the United States Northeast market 50 percent of the applied-for quantities, the Board is not prepared to approve the licence term or the quantities requested by Transco. However, the Board is prepared to issue a licence as follows:

A new licence for the importation of gas at Sarnia, Ontario and for the exportation of gas at Niagara Falls, Ontario for a 12-year period commencing 1 November 1984 under the following conditions:

(a) for import at Sarnia, Ontario.

(i)

Period	Daily (10^3m^3)	Annual (10^6m^3)
1 Nov '84 to 31 Oct '93	4 249.2	1 555.2
1 Nov '93 to 31 Oct '94	3 186.9	1 166.4
1 Nov '94 to 31 Oct '95	2 124.6	777.6
1 Nov '95 to 31 Oct '96	1 062.3	388.8

(ii) a total quantity that may be imported during the term of the licence of 16 329.6 x 10^6m^3.

(b) for export at Niagara Falls, Ontario.

(i)

Period	Daily (10^3m^3)	Annual (10^6m^3)
1 Nov '84 to 31 Oct '93	8 498.4	1 555.2
1 Nov '93 to 31 Oct '94	6 373.8	1 166.4
1 Nov '94 to 31 Oct '95	4 249.2	777.6
1 Nov '95 to 31 Oct '96	2 124.6	388.8

(ii) a total quantity that may be exported during the term of the licence of 16 329.6 x 10^6m^3.

(iii) a provision that no exports under this licence take place unless said exports shall have been imported under the same licence.

5.15 Union Gas

Union Gas applied for an extension to the term of its existing Licence GL-64 to 30 April 1993 to export SNG.

It is the Board's view that Union's SNG export does not affect the surplus calculation, however, the Board is cognizant of the fact that under certain circumstances the deliverability provided by this source may be required to satisfy Canadian requirements in the future. As a consequence the Board is prepared to allow exports at reduced levels during the last two years of the licence to 31 October 1992 and is not prepared to approve the term quantity requested by Union Gas. However, the Board is prepared to issue a new licence commencing 1 November 1985 to replace Licence GL-64 for export at Windsor, Ontario as follows:

(i)

Period	Daily (10^3m^3)	Annual (10^6m^3)
1 Nov '85 to 31 Oct '90	1 100.0	284.0
1 Nov '90 to 31 Oct '91	732.6	189.1
1 Nov '91 to 31 Oct '92	366.3	94.6

(ii) a total quantity that may be exported during the term of the licence of 1 703.7 x 10^6m^3.

(iii) during the period 1 November 1992 to 31 October 1993, a make-up provision up to the maximum daily quantity of 1 100.0 x 10^3m^3, subject to the availability of capacity and deliverability, to permit recovery of quantities of gas paid for but not taken under the terms of the sales contract or 284.0 x 10^6m^3 whichever is less.

5.16 Westcoast Transmission

Westcoast applied to amend and extend Licence GL-41 to 31 October 1996 and to add Kingsgate, British Columbia as an additional delivery point in the licence.

Having regard to its findings on surplus and to its decision to allow exports at reduced levels in the last two years of licence extensions to 31 October 1992, the Board is not prepared to approve the licence term or the quantities requested by Westcoast. However, the Board is prepared to issue an order to amend Licence GL-41 and to issue two new licences commencing 1 November 1989 to replace Licence GL-41 for export at Huntingdon and Kingsgate, British Columbia and at Monchy, Saskatchewan as follows:

(a) to amend Licence GL-41 to provide for the following:

(i) the increase of the maximum daily and annual quantities in the licence to:

Period	Daily (10^3m^3)	Annual (10^6m^3)
1 Apr '83 to 31 Oct '83	26 039.0	4 706.2
1 Nov '83 to 31 Oct '89	26 039.0	8 067.8

(ii) an increase in the total term quantity to 143 495.2 x 10^6m^3.

(iii) a provision limiting the exports at Monchy, Saskatchewan to 1 416.4 x 10^3m^3 per day and 517.0 x 10^6m^3 per year for the period 1 April 1983 to 31 October 1989.

(iv) a provision limiting the exports at Kingsgate, British Columbia to 2 832.8 x 10^3m^3 per day for the period 1 April 1983 to 31 October 1989.

(b) to issue a new licence commencing 1 November 1989 providing for the export of gas at Huntingdon, British Columbia under the following conditions:

(i)

Period	Daily ($10^3 m^3$)	Annual ($10^6 m^3$)
1 Nov '89 to 31 Oct '92	8 498.3	3 101.9
1 Nov '92 to 31 Oct '93	6 373.7	2 326.4
1 Nov '93 to 31 Oct '94	4 249.1	1 550.9
1 Nov '94 to 31 Oct '95	2 124.6	775.5

(ii) a total quantity that may be exported during the term of the licence of 13 958.5 x $10^6 m^3$.

(iii) a provision to condition the licence to the approval of the proposed offline sale by Northwest to Texas Eastern and/or Transwestern.

(c) to issue a new licence commencing 1 November 1989 providing for the export of gas at Huntingdon and Kingsgate, British Columbia and at Monchy, Saskatchewan under the following conditions:

(i)

Period	Daily ($10^3 m^3$)	Annual ($10^6 m^3$)
1 Nov '89 to 31 Oct '90	13 731.0	4 637.1
1 Nov '90 to 31 Oct '91	9 144.8	3 088.3
1 Nov '91 to 31 Oct '92	4 572.4	1 544.1

(ii) a total quantity that may be exported during the term of the licence of 9 269.5 x $10^6 m^3$.

(iii) a provision limiting the exports at Monchy, Saskatchewan to 1 416.4 x $10^3 m^3$ per day.

(iv) a provision limiting the exports at Kingsgate, British Columbia to 2 832.8 x $10^3 m^3$ per day.

The foregoing Chapters set forth our Reasons for Decisions and our Decisions in the matters of Phase II and Phase III of the Gas Export Omnibus Hearing, 1982.

C. G. Edge

C.G. Edge
Presiding Member

R.B. Horner

R.B. Horner, Q.C.
Member

A.B. Gilmour

A.B. Gilmour
Member

Ottawa, Ontario
January 1983

Appendices

December 14, 1981

To: Applicants and Interested Parties

Re: Gas Export Omnibus Hearing, 1982

The National Energy Board has received 16 applications for licences to export natural gas or to vary existing licences and has been advised that a number of other applications will be filed shortly.

Conditions in the natural gas industry have been changing rapidly and export licences for natural gas have been granted in the past with terms and conditions that may no longer be appropriate.

In the Board's Canadian Energy Supply and Demand Inquiry, the Report on which was published in June 1981, representations were made that the Board's tests for determining the surplus of Canadian gas for export should be modified. That inquiry was not specifically designed to deal with the Board's surplus tests and based on the evidence tendered, the Board, at that time, was not persuaded to change the surplus determination procedures. Subsequently the Board has received further representations that the method of determining surplus should be re-examined.

It appears to the Board, therefore, to be timely to undertake a review of the conditions attached to existing export licences and the procedure currently used to determine the surplus of natural gas for export, including the allowance to be made for export licences in the determination of surplus.

The Board has decided to hold a hearing dealing with these matters. The hearing will be held in three phases.

Phase I of the hearing, the Review Phase, will begin on 16 March 1982 in Ottawa and will examine matters relating to the terms and conditions in existing export licences and in the contracts associated with them. This phase of the hearing will also deal with the procedure for determining surplus. The Board expects to make its views known on these matters before proceeding to the next phase.

Phase II of the hearing, the Licence Phase, which is expected to begin in early July, will examine the economic, contractual, regulatory and other aspects of the individual applications for export licences.

This will be followed by Phase III of the hearing, the Surplus Phase, which will consider demand, supply, and the surplus, if any, available for export. In this phase of the hearing, the Board will also determine to which, if any, of the applicants it should recommend that Governor in Council approve the issuance of export licences. If export licences are issued, a further hearing may be needed under Part III of the Act if new pipeline facilities are required for the export of gas.

Attached is a copy of the Board's Hearing Order, together with its "Guidelines for Submissions" for use by the applicants and intervenors in the preparation of their evidence.

Yours truly,

G. Yorke Slader,
Secretary

ORDER NO. GH-6-81

IN THE MATTER OF the National Energy Board Act and the Regulations made thereunder;

AND IN THE MATTER OF a review of existing natural gas licences and the Board's surplus determination procedures;

AND IN THE MATTER OF applications made by Pan-Alberta Gas Ltd., Sulpetro Limited and TransCanada PipeLines Limited for licences under Part VI of the National Energy Board Act for the export of natural gas to the United States of America;

AND IN THE MATTER OF applications made by Alberta and Southern Gas Co. Ltd., Pan-Alberta Gas Ltd. and TransCanada PipeLines Limited under Part VI of the National Energy Board Act to vary existing natural gas export licences.

B E F O R E the Board on Monday, the 14th day of December 1981.

UPON the Board, by its own motion, having decided to conduct a review of existing natural gas licences and of its surplus determination procedures;

AND UPON Alberta and Southern Gas Co. Ltd., hereinafter called "Alberta and Southern", having filed with the Board an application dated the 24th day of August 1981, under Part VI of the National Energy Board Act, to vary existing natural gas export Licences GL-3, GL-16, GL-24 and GL-35;

AND UPON Pan-Alberta Gas Ltd., hereinafter called "Pan-Alberta" having filed with the Board an application dated the 14th day of October 1981, under Part VI of the National Energy Board Act, to vary natural gas export Licences GL-58, GL-59, and GL-63;

AND UPON Pan-Alberta having filed with the Board an application dated the 14th day of October 1981 for a licence, under Part VI of the National Energy Board Act, to export natural gas at a point on the international boundary between Canada and the United States of America near St. Stephen, in the Province of New Brunswick;

AND UPON Sulpetro Limited, hereinafter called "Sulpetro" having filed with the Board an application dated the 27th day of July 1981 for a licence, under Part VI of the National Energy Board Act, to export natural gas at a point on the international boundary between Canada and the United States of America near Niagara Falls, in the Province of Ontario;

AND UPON TransCanada PipeLines Limited, hereinafter called "TransCanada", having filed with the Board an application dated the 19th day of November 1980, as amended on the 13th day of August 1981 for licences, under Part VI of the National Energy Board Act, to export natural gas at a point on the international boundary between Canada and the United States of America near Niagara Falls, in the Province of Ontario;

AND UPON TransCanada having filed with the Board an application dated the 26th day of June 1981 for licences, under Part VI of the National Energy Board Act, to export natural gas at a point on the international boundary between Canada and the United States of America near Emerson, in the Province of Manitoba and/or Lake Erie, in the Province of Ontario;

AND UPON TransCanada having filed with the Board applications dated the 26th day of June 1981 and the 27th day of October 1981 to vary, under Part VI of the National Energy Board Act, existing natural gas export Licences GL-18, GL-20, GL-37, GL-38, and GL-60.

AND UPON the Board having been advised that other parties may be making applications under Part VI of the Act either to export natural gas or to vary existing natural gas export licences, including applications for licences to export liquefied natural gas to Japan.

IT IS ORDERED THAT:

1.The Board will hold public hearings on the applications in three phases, to be referred to as follows:

Phase I - Review Phase
Phase II - Licence Phase
Phase III - Surplus Phase

2. The matters the Board wishes to be addressed in each phase are outlined in Annex I of this Order.

REVIEW PHASE

3. The Review Phase will commence at 9.30 a.m. on Tuesday, 16 March 1982, in the hearing room of the Board, located at 473 Albert Street, Ottawa, Ontario, and possibly at other locations as the Board may by subsequent order direct. The hearing will be conducted in either of the two official languages and simultaneous interpretation will be provided should a party to the proceedings request such facilities in its intervention.

4. Any party intending to intervene in the Review Phase shall file on or before the 5th day of February 1982, with the Secretary of the Board, thirty-five (35) copies of a written statement, in either of the two official languages, containing its submission following the guidelines in Annex I, together with any supporting material, and as soon as possible thereafter shall serve one (1) copy of its submission and supporting material upon each of the parties named in Annex II. This submission shall contain a concise statement of the facts from which the nature of the intervenor's interest in the Review Phase may be determined; it shall be endorsed with the name and address of the intervenor or its solicitor to whom communications may be sent; it shall state the official language in which the intervenor wishes to be heard. A list of intervenors will be distributed to all interested parties by the Board. Upon receipt of this list, all intervenors shall also serve a copy of their submission upon each other party who has intervened pursuant to this paragraph. Any party who files a submission after the 5th day of February 1982, must file and serve a notice of motion, requesting leave to submit a late submission. Such notice shall be filed and served in accordance with Paragraph 22.

5. Any party who has filed a written submission in accordance with Paragraph 4 and who wishes to present direct evidence in the hearing, shall prepare direct evidence written in question and answer form with lines numbered for each of its witnesses and shall on or before the 22nd day of February 1982, file thirty-five (35) copies with the Secretary of the Board and serve one (1) copy of the same upon each other party who has intervened pursuant to Paragraph 4 of this Order.

6. Procedural orders may be issued by the Board with respect to the conduct of the Review Phase of the hearing.

7. The Board expects to issue its Findings on the Review Phase before the commencement of the Licence Phase.

LICENCE AND SURPLUS PHASES

8. Any party who wishes to file an application, or any existing Applicant who wishes to revise its existing application or submit a new application for consideration in the Licence and Surplus Phases, shall file on or before the 2nd day of April 1982 thirty-five (35) copies thereof with the Secretary of the Board.

9. The Board will arrange to have published a further notice of hearing advising of the new or revised applications filed.

10. Each Applicant shall, on or before the 2nd day of April 1982, serve one (1) copy of its application on every other applicant, one copy on each of the parties listed in Annex II and as soon as possible one copy on each intervenor. A list of all the intervenors in the Licence Phase and Surplus Phase will be distributed by the Board.

11. All Applicants are considered to be intervenors with respect to all other applications to be dealt with in the Licence and Surplus Phases.

12. Any party who intends to participate or intervene in the Licence or Surplus Phase shall file with the Secretary of the Board, on or before the 14th day of May 1982, thirty-five (35) copies of a written statement, in either of the two official languages, containing its intervention or submission together with any supporting information, particulars, or documents. This statement shall contain a concise statement of the facts from which the nature of the party's interest in the proceedings may be determined; it may admit or deny any or all of the facts alleged in any of the applications in which the intervenor is interested; it shall be endorsed with the name and address of the party or its solicitor to whom communications may be sent; it shall state in which of the two official languages the party wishes to be heard; it shall state whether the party wishes to receive a copy or a portion of any of the applications filed. Any party shall, in addition, as soon as possible serve three (3) copies of its written statement and supporting information upon each of the Applicants and one (1) copy upon each of the parties named in Annex II of this Order and as soon as possible one (1) copy

upon each party who has filed a written statement in accordance with this paragraph. A list of all the parties will be distributed by the Board. Any party who files a written statement after the 14th day of May 1982 must file with the Secretary of the Board a notice of motion, in accordance with Paragraph 22, requesting leave to file a late written statement.

13. Upon receipt of a copy of the written statement referred to in Paragraph 12 hereof containing a request for a copy of the application or a portion thereof, the Applicant to which the request is sent to shall, as soon as possible, either provide the same or apply to the Board in accordance with Paragraph 22 for relief from this requirement of service.

14. Each Applicant shall prepare its direct evidence written in question and answer form with lines numbered for each of its witnesses and shall, on or before the 11th day of June 1982, file thirty-five (35) copies thereof with the Secretary of the Board, and, as soon as possible, serve one (1) copy on each party included in the list of intervenors received from the Board.

15. Any party who has intervened pursuant to Paragraph 12 hereof and who wishes to adduce direct evidence in the hearing shall prepare its direct evidence written in question and answer form with lines numbered and shall, on or before the 25th day of June 1982, file thirty-five (35) copies with the Secretary of the Board, and serve one (1) copy of the same upon each Applicant and one (1) on each party included in the list of intervenors received from the Board.

16. Any parties who wish to update their calculation of surplus in light of the Board's Findings on the Review Phase or to incorporate 1981 year-end data shall on or before the 30th day of July 1982 file thirty-three (33) copies thereof with the Secretary of the Board in Ottawa, and two (2) copies with the office of the National Energy Board in Calgary at 3303 - 33rd St. N.W. Calgary, Alberta T2L 2A7, and one (1) copy on each party included in the list of intervenors received from the Board.

17. The applications of Alberta and Southern, Pan-Alberta, and TransCanada for leave under Rule 22 of the National Energy Board Rules of Practice and Procedure, be and are hereby denied. This denial is without prejudice to any further applications made in accordance with Paragraph 22 by the aforementioned parties or by any party which has intervened pursuant to Paragraph 12, which identify specific evidence taken before, or specific reports, findings, or orders of the Board or of a provincial tribunal. Wherever possible, such applications should be made on or before the applicable date fixed for the filing of written direct evidence.

18. TransCanada's request for a general direction of the Board pursuant to subsection 3(2) of the National Energy Board Rules of Practice and Procedure dispensing with compliance with the provisions of Section 5 of the Rules, be and is hereby denied for lack of specificity.

19. Alberta and Southern's request that it be relieved of the requirement to furnish the information otherwise required by Section 4(2)(b) of the National Energy Board's Part VI Regulations, be and is hereby denied.

20. Procedural orders will be issued by the Board regarding the timing, the conduct, and any other matters concerning the Licence Phase and the Surplus Phase of the hearing.

GENERAL INFORMATION

21. Where an Applicant, or any party who has intervened pursuant to Paragraphs 4 and 12 hereof wishes to obtain additional information from an Applicant or any other party to these proceedings in respect of matters raised in filings made with the Board, such requests shall be made in writing, and the Applicant or the party to whom the request is made, shall, as soon as possible, either provide a written response to the request or refer the question to the Board under Paragraph 22 hereof. Both written requests and the responses thereto shall be filed as exhibits at the hearing by the party answering the request.

22. If any question arises upon which the decision of the Board may be required, ten (10) copies of a notice of motion with respect thereto shall be filed with the Secretary of the Board, and one (1) copy served on each Applicant and each intervenor, and the motion shall be heard by the Board on a date to be fixed by it.

23. Any party who files a written statement in accordance with Paragraphs 4 and 12, or written direct evidence in accordance with Paragraphs 5, 13 and 15, or revised information in accordance with Paragraph 16, or a notice of motion in

accordance with Paragraph 22, shall file proof of service thereof and two (2) copies of the document with the Board at the opening of the hearing.

24. A Schedule of hearing and filing dates is attached as Annex III.

25. Any interested party may examine copies of the applications and submissions filed therewith at the office of the:

National Energy Board,
Trebla Building,
473 Albert Street,
Ottawa, Ontario
K1A OE5

or at the offices of the Applicants at the following addresses:

Alberta and Southern Gas Co. Ltd.,
24th Floor East Tower, Esso Plaza,
425 - 1st Street S.W.,
Calgary, Alberta
T2P 3L8

Pan-Alberta Gas Ltd.,
350 Bow Valley Square I,
202 - 6th Avenue S.W.,
Calgary, Alberta
T2P 2R9

Sulpetro Limited,
Suite 3200,
Bow Valley Square 3,
255 - Fifth Avenue S.W.,
Calgary, Alberta
T2P 3G8

Legal Library,
TransCanada PipeLines Limited,
55th Floor,
Commerce Court West,
Toronto, Ontario
M5L 1C2

DATED at the City of Ottawa, in the Province of Ontario, this 14th day of December, 1981.

NATIONAL ENERGY BOARD

G. Yorke Slader
Secretary

ANNEX I
to Order GH-6-81

Gas Export Omnibus Hearing, 1982
Guidelines for Submissions

In addition to the information required to be filed under the National Energy Board Part VI Regulations and the National Energy Board Rules of Practice and Procedure, the Board requests that Applicants and intervenors use the following guidelines in the preparation of submissions. All submissions should be expressed in SI units.

PHASE I - REVIEW PHASE

In the first phase of the hearing, the Board requests that the following licence issues be addressed:

1) Whether annual averaging conditions in licences are necessary.

2) The factors that influence the determination of the maximum daily quantity and the relationship between the maximum daily level and the annual level, and in turn the relationship to the term quantity.

3) Whether take-or-pay conditions should be included in the licence.

4) Whether to allow for recovery of quantities paid for but not taken at the expiry of the licence.

In regard to other matters relating to licences, interested parties are asked to provide comment on the following:

5) The conversion of licensed quantities to energy units (joules).

6) The need to include measurement and operating tolerance levels in the licence.

7) The need to simplify and standardize existing licences, including changing all licences to contract year (November-October) or calendar year.

8) The need to issue consolidated versions of licences to reflect all amendments to date.

Also as part of Phase I, the Board requests that the following issues with respect to the procedure for determining surplus be addressed:

9) The appropriateness of the existing three-test procedure: the current deliverability test, the current reserves test and the future deliverability test.

10) The allowance to be made in the surplus determination procedure for gas which may be exported under licence, and whether gas subject to take-or-pay clauses should be differentiated from other gas in the licence for this purpose.

11) The consideration to be given to reserves additions.

12) The use of storage to enhance deliverability.

13) The treatment to be accorded frontier gas reserves.

14) The compatibility of any proposed revision to the surplus determination procedure with provincial protection procedures.

15) The need for determination of surplus by region; e.g., British Columbia and the Southern part of the Territories, Alberta and other Western provinces, Atlantic provinces, Arctic Islands, Mackenzie Delta and Beaufort Sea.

Where possible, interested parties are asked to illustrate numerically the effect of any proposed changes in the allowance to be made for authorized licence quantities or the surplus determination procedure. To facilitate comparison between submissions, such calculations should be based on supply and demand data taken from pages 216 to 218 of the Board's June 1981 Report on Canadian Energy Supply and Demand. In addition, parties may show the effects based on supply/demand forecasts they believe are more likely to occur.

Natural gas licence holders will be expected to provide a witness to speak to the circumstances pertaining to their licence or licences. United States importers are similarly encouraged to provide witnesses.

PHASE II - LICENCE PHASE

In the second phase of the hearing, the Board requests that the following issues be addressed:

1) An overview of export markets for Canadian gas in the United States and in the Far East to include estimates of quantities marketable either directly or by displacement, as well as pricing, regulatory and other considerations.

2) A summary of the importing company's supply/demand balances for its total market areas to the year 2000. This summary is to include a forecast of maximum day and annual requirements by market sector (residential, commercial, industrial, power generation and off-line sales) and a forecast of the maximum day and total annual supply available by region.

3) The status and type of sales contract negotiations and import authorizations, state regulatory policies, etc.

4) A review of the gas supply under contract to the applicant and the status of provincial removal authorizations.

5) A cost-benefit study of the proposed export.

PHASE III - SURPLUS PHASE

In the third phase of the hearing the Board requests that the following issues be addressed:

1) Established reserves, reserves additions, and deliverability of Canadian natural gas, including frontier regions.

2) The domestic demand for natural gas, to the year 2000, in both existing and new markets, showing how it relates to the total demand for energy. (Submittors are requested to provide a national and regional breakdown by sector of Canadian natural gas demand for each year 1979 to 1985 and for the years 1990, 1995, and 2000.)

3) The allowance for authorized exports of natural gas including any amendments by the Board in its decision to be issued after the completion of Phase I of the hearing.

4) The determination of surplus by using the procedure outlined by the Board in its decision to be issued after the completion of Phase I of the hearing.

5) The allocation of any available surplus to applicants.

ORDER NO. PO-1-GH-6-81

IN THE MATTER OF the National Energy Board Act and the Regulations made thereunder;

AND IN THE MATTER OF a review of existing natural gas licences and the Board's surplus determination procedures;

AND IN THE MATTER OF applications made by Pan-Alberta Gas Ltd., Sulpetro Limited and TransCanada PipeLines Limited for licences under Part VI of the National Energy Board Act for the export of natural gas to the United States of America;

AND IN THE MATTER OF applications made by Alberta and Southern Gas Co. Ltd., Pan-Alberta Gas Ltd. and TransCanada PipeLines Limited under Part VI of the National Energy Board Act to vary existing natural gas export licences.

B E F O R E the Board on Tuesday, the 20th day of April 1982.

UPON the Board, by its own motion, having decided to conduct a review of existing natural gas licences and of its surplus determination procedures;

AND UPON Alberta and Southern Gas Co. Ltd., hereinafter called "Alberta and Southern", having filed with the Board an application dated the 24th day of August 1981, under Part VI of the National Energy Board Act, to vary existing natural gas export Licences GL-3, GL-16, GL-24 and GL-35;

AND UPON Pan-Alberta Gas Ltd., hereinafter called "Pan-Alberta", having filed with the Board an application dated the 14th day of October 1981, under Part VI of the National Energy Board Act, to vary natural gas export Licences GL-58, GL-59, and GL-63;

AND UPON Pan-Alberta having filed with the Board an application dated the 14th day of October 1981 for a licence, under Part VI of the National Energy Board Act, to export natural gas at a point on the international boundary between Canada and the United States of America near St. Stephen, in the Province of New Brunswick;

AND UPON Sulpetro Limited, hereinafter called "Sulpetro", having filed with the Board an application dated the 27th day of July 1981 for a licence, under Part VI of the National Energy Board Act, to export natural gas at a point on the international boundary between Canada and the United States of America near Niagara Falls, in the Province of Ontario;

AND UPON TransCanada PipeLines Limited, hereinafter called "TransCanada", having filed with the Board an application dated the 19th day of November 1980, as amended on the 13th day of August 1981, for licences, under Part VI of the National Energy Board Act, to export natural gas at a point on the international boundary between Canada and the United States of America near Niagara Falls, in the Province of Ontario;

AND UPON TransCanada having filed with the Board an application dated the 26th day of June 1981 for licences, under Part VI of the National Energy Board Act, to export natural gas at a point on the international boundary between Canada and the United States of America near Emerson, in the Province of Manitoba and/or Lake Erie, in the Province of Ontario;

AND UPON TransCanada having filed with the Board applications dated the 26th day of June 1981 and the 27th day of October 1981 to vary, under Part VI of the National Energy Board Act, existing natural gas export Licences GL-18, GL-20, GL-37, GL-38, and GL-60;

AND WHEREAS the Board by Paragraph 8 of Order GH-6-81 ordered that any party who wishes to file an application, or any existing Applicant who wishes to revise its existing application or submit a new application for consideration in the Licence and Surplus Phases, shall do so on or before the 2nd of April 1982, the Board has received the following applications under Part VI of the National Energy Board Act from:

1. Canadian-Montana Pipe Line Company, hereinafter called "Canadian-Montana", dated 1 April 1982, to vary existing natural gas export Licences GL-5, GL-17, GL-25, GL-36, and GL-52;

2. Carter Energy Limited, hereinafter called "Carter", dated 31 March 1982, for a licence to export liquefied natural gas from a point near Prince Rupert, British Columbia, to Korea and Japan;

3. Columbia Gas Development of Canada Ltd., hereinafter called "Columbia", dated 25 March

1982, to vary existing natural gas export Licence GL-54;

4. Consolidated Natural Gas Limited, hereinafter called "Consolidated", dated 16 December 1981, and further amended on 30 March 1982, to vary existing natural gas export Licence GL-61;

5. Dome Petroleum Limited, hereinafter called "Dome", dated 31 March 1982, for a licence to export liquefied natural gas at a point west of Port Simpson Bay, British Columbia, to Japan;

6. KannGaz Producers Ltd., hereinafter called "KannGaz", dated 22 March 1982, for a licence to export natural gas at a point on the international border near Niagara Falls, Ontario;

7. Niagara Gas Transmission Limited, hereinafter called "Niagara", dated 14 April 1982, under subsection 17(2) of the National Energy Board Act, to vary existing natural gas export Licence GL-55;

8. Pan-Alberta, dated 30 March 1982, for a licence to export natural gas at a point on the international border near Niagara Falls, Ontario;

9. ProGas Limited, hereinafter called "ProGas", dated 31 March 1982, to vary existing natural gas export Licence GL-56;

10. ProGas, dated 31 March 1982, for a licence to export natural gas at points on the international border at Emerson, Manitoba, Niagara Falls, Ontario and Kingsgate, British Columbia;

11. Rim Gas Ltd., dated 24 March 1982, for a licence to export liquefied natural gas from a point near Bish Cove, British Columbia, to Japan;

12. Sulpetro, an amendment to its application dated 27 July 1981 for a licence to export natural gas at a point on the international border near Niagara Falls, Ontario;

13. TransCanada, dated 23 December 1981, to vary existing natural gas export Licence GL-60;

14. TransCanada, dated 2 April 1982, which amends and supersedes its application for licences to export natural gas dated 19 November 1980, as amended on 13 August 1981, and its application dated 26 June 1981, and which incorporates its applications dated 27 October 1981 to vary existing export Licences GL-18, GL-20, GL-37, and GL-38 and its application dated 23 December 1981 to vary existing export Licence GL-60;

15. Transcontinental Gas Pipe Line Corporation, hereinafter called "Transco", dated 31 August 1981, for a licence for the importation of natural gas at a point on the international border near St. Clair, Michigan, and for the exportation of such gas at a point on the international border near Port Colborne, Ontario;

16. Union Gas Limited, hereinafter called "Union", dated 15 January 1982, to vary existing gas export Licence GL-64;

17. Westcoast Transmission Company Limited, hereinafter called "Westcoast" dated 1 April 1982, under subsection 17(2) and Part VI of the National Energy Board Act, to vary export Licence GL-41.

LICENCE AND SURPLUS PHASES

IT IS ORDERED THAT;

1. The matters the Board wishes to be addressed in the Licence and Surplus Phases are outlined in Annex I of Order No. GH-6-81.

2. The Licence Phase will commence at 9:00 a.m. on Tuesday, 13 July 1982, in the hearing room of the Board, located at 473 Albert Street, Ottawa, Ontario. All of Phase II will be held in Ottawa. The hearing will be conducted in either of the two official languages and simultaneous interpretation will be provided should a party to the proceedings request such facilities in its intervention. The Board will announce by a subsequent order, the dates, times and place for Phase III of the hearing.

3. The hearing hours for Phase II will be from 9:00 a.m. to 1:00 p.m. on Tuesday, 13 July 1982, and for the remainder of Phase II the hearing hours will be from 9:00 a.m. to 12:30 p.m. and 2:00 p.m. to 4:30 p.m. on Mondays and Wednesdays and from 9:00 a.m. to 1:00 p.m. on Tuesdays and Thursdays. There will be no hearing on Fridays. The Board will announce any changes in the hearing hours as the circumstances may require.

4. In Phase II of the Hearing the Board will first deal with the overview of export markets for Canadian gas (Item 1 of the Guidelines for Submissions, Annex I of Order No. GH-6-81). The Board will then deal with the individual

applications. Annex I to this order is a Guideline to Items 1 and 2 of the Guidelines for Submission.

5. The Applicants shall arrange among them to have the Notice of Hearing in the form prescribed by the Board as set forth in the Notice attached hereto and which forms part of this Order, published not later than 30 April 1982 in one issue each of the "Times" and the "Colonist" in Victoria, the "Sun" and the "Province" in Vancouver; the "Herald" in Calgary and the "Journal" in Edmonton; the "Leader Post" and "L'eau Vive" in Regina; "The Winnipeg Free Press" and "La Liberté" in Winnipeg; "The Citizen" and "Le Droit" in Ottawa, "The Globe and Mail", the "Financial Times", "The Financial Post" and "Le Toronto Express" in Toronto; "The Gazette" and "Le Devoir" in Montreal, "The Chronicle Telegraph" and "Le Soleil" in Québec; the "Telegraph Journal" and "L'Evangéline" in Saint John; "The Chronicle Herald" and the "Mail Star" in Halifax; the "Telegram" in St. John's; "The Guardian" in Charlottetown; the "Star" in Whitehorse; the "News/North" in Yellowknife: and as soon as possible in the "Canada Gazette".

6. Each applicant is required to file as an exhibit two copies of its application and supporting documents and two copies of an affidavit of service of such documents. Each intervenor is required to file as an exhibit two copies of its intervention or submission together with any supporting information, particulars, or documents and two copies of an affidavit of service of such documents. Applicants and intervenors are requested to file the above-mentioned documents by mail with the Board on or before 2 July 1982 so as to be incorporated in a pre-arranged exhibit list.

7. The applications of Carter, Consolidated, ProGas and Transco for leave under Rule 22 of the National Energy Board Rules of Practice and Procedure, be and are hereby denied. This denial is without prejudice to any further applications made in accordance with Paragraph 22 of Order No. GH-6-81 by the aforementioned parties or by any party which has intervened pursuant to Paragraph 12, which identify specific evidence taken before, or specific reports, findings, or orders of the Board or of a provincial tribunal. Wherever possible, such applications should be made on or before the applicable date fixed for the filing of written direct evidence.

8. Pan-Alberta's application for leave under subsection 3(2) of the National Energy Board Rules of Practice and Procedure to file nine (9) copies of Volumes 2 through 12 of the application containing the reservoir parameters, isopachs and land maps referred to in the "Gas Supply" section of its application, and to dispense with service of the said Volumes on all other parties to these proceedings provided that the Applicant will make the said Volumes available for inspection at its offices in Ottawa and Calgary and as well at the place(s) of hearing of the application, be and is hereby granted on the condition that two (2) copies are filed with the Board's Office in Calgary.

9. ProGas' application for relief from the requirement to serve the deliverability back-up data on all interested parties, on the understanding that copies will be made available for examination by all proper parties at the offices of ProGas Limited in Calgary and the National Energy Board in Ottawa, be and is hereby granted on the condition that two (2) copies are filed with the Board's Office in Calgary.

10. ProGas' request for a general direction of the Board pursuant to subsection 3(2) of the National Energy Board Rules of Practice and Procedure dispensing with compliance with the provisions of Section 5 of the Rules, be and is hereby denied for lack of specificity.

11. Carter's application that it be granted relief from the requirement of service of Volumes I and II of its application on the parties named in Annex II of Order No. GH-6-81 and on the intervenors in Phase II, be and is hereby denied.

12. Any interested party may examine copies of the applications and submissions filed therewith at the office of the:

National Energy Board,
Trebla Building,
473 Albert Street,
Ottawa, Ontario
K1A OE5

or at the offices of the Applicants at the following addresses:

Alberta and Southern Gas Co. Ltd.,
24th Floor East Tower, Esso Plaza,
425 - 1st Street S.W.,
Calgary, Alberta
T2P 3L8

Canadian-Montana Pipe Line Company,
520 Britannia Building,
703 6th Avenue S.W.,
Calgary, Alberta
T2P OT9

Carter Energy Limited,
1066 W. Hastings Street,
Suite 2320,
Vancouver, British Columbia
V6E 3X1

Columbia Gas Development of Canada Ltd.,
1000 Standard Life Building,
639 - 5th Avenue S.W.,
Calgary, Alberta
T2P OM9

Consolidated Natural Gas Limited,
130 Elveden House,
717 - 7th Avenue S.W.,
Calgary, Alberta
T2P OZ3

Dome Petroleum Limited,
31st Floor,
333 - 7th Avenue S.W.,
Calgary, Alberta
T2P 2H8

KannGaz Producers Ltd.,
504 Lancaster Building,
304 Eigth Avenue S.W.,
Calgary, Alberta
T2P 2C2

Niagara Gas Transmission Limited,
Suite 4200,
First Bank Tower,
P.O. Box 90,
1 First Canadian Place,
Toronto, Ontario
M5X 1C5

Pan-Alberta Gas Ltd.,
350 Bow Valley Square I,
202 - 6th Avenue S.W.,
Calgary, Alberta
T2P 2R9

ProGas Limited,
940 Selkirk House,
555 - 4th Avenue S.W.,
Calgary, Alberta
T2P 3E7

Rim Gas Ltd.,
Library,
Guinness House,
729 - 7th Avenue S.W.,
8th Floor,
Calgary, Alberta
T2P 2M7

Sulpetro Limited,
Suite 3200,
Bow Valley Square 3,
255 - Fifth Avenue S.W.,
Calgary, Alberta
T2P 3G8

Legal Library,
TransCanada PipeLines Limited,
55th Floor,
Commerce Court West,
Toronto, Ontario
M5L 1C2

Transcontinental Gas Pipe Line Corporation,
2700 South Post Oak Road,
P.O. Box 1396,
Houston, Texas
U.S.A. 77001

Union Gas Limited,
50 Keil Drive N.,
P.O. Box 2001,
Chatham, Ontario
N7M 5M1

Westcoast Transmission Company Limited,
1333 West Georgia Street,
Vancouver, British Columbia
V6E 3K9

13. Annex II of Order No. GH-6-81 is hereby superseded by the attached revised Annex II.

DATED at the City of Ottawa, in the Province of Ontario, this 20th day of April, 1982.

NATIONAL ENERGY BOARD

G. Yorke Slader,
Secretary

ANNEX 1
to PO-1-GH-6-81

Gas Export Omnibus Hearing, 1982 - Phase II
Guideline for Market Information

Introduction

The Guidelines for Submissions, Annex I to Order GH-6-81, requested that the following issues be addressed:

1) An overview of export markets for Canadian gas in the United States and in the Far East to include estimates of quantities marketable either directly or by displacement, as well as pricing, regulatory and other considerations.

2) A summary of the importing company's supply/demand balances for its total market area to the year 2000. This summary is to include a forecast of maximum day and annual requirements by market sector (residential, commercial, industrial, power generation and off-line sales) and a forecast of the maximum day and total annual supply available by region.

While any party may wish to respond to Issue 1 as set out in this Guideline, it is primarily intended for guidance to Applicants seeking new or revised export licences for the sale of Canadian gas to or through inter-state pipeline companies in the United States, and/or the export of LNG to Korea and Japan.

Exports to United States

The overview, Item 1 above, should identify for the Board's consideration, an estimate of:

a) total supply of natural gas to the United States from

   (i) indigenous sources (including Alaska),

   (ii) synthetic production, and

   (iii) supplemental supplies (imports) of pipeline gas and LNG from Canada, Mexico and other countries for the years 1981, 1985, 1990 and 2000,

   under various pricing scenarios as considered appropriate by the applicant e.g., Natural Gas Policy Act of 1978 and/or accelerated deregulation with specific reference to the impact of imports of Mexican gas on imports from Canada;

b) total demand for natural gas by market sector, residential, commercial, industrial and power generation, for the same years and the same pricing scenarios as shown in Item a) above;

c) world crude oil selling prices and an assessment of the impact that world crude oil prices will have on the supply, demand, and selling price for natural gas in the United States; and

d) the supply and selling price of alternative sources of energy in international trade, e.g., heavy fuel oil, LNG, and propane, and an assessment of the impact that competition from these commodities will have on markets for natural gas in the United States.

The summary, Item 2 above, should identify, for the Board's consideration an estimate of:

e) the United States importer's annual supply of natural gas showing the maximum day and annual volume from each domestic supply region and foreign import source to the year 2000, and the implications of federal and state regulatory policy directives on the acquisition of such supplies;

f) the United States importer's annual sales of natural gas for its pipeline or distribution system showing the maximum day and annual requirements by market sector, residential, commercial, industrial, power generation, and off-line sales, to the year 2000, and

g) the United States importer's annual supply and demand balance indicating its need for supplies of Canadian natural gas to the year 2000.

Exports to Japan and/or Korea

The overview, Item 1 above, should identify separately for each country proposed to be served, for the Board's consideration, an estimate of:

h) total supply of natural gas, including LNG, from

(i) indigenous sources,

(ii) synthetic production, and

(iii) imports of LNG by country of origin for the years 1981, 1985, 1990 and 2000,

under various pricing scenarios as considered appropriate by the Applicant.

i) total demand for natural gas by market sector, residential, commercial, industrial, and power generation, for the same years and the same pricing scenarios as shown in Item h) above.

j) world crude oil selling prices and an assessment of the impact that world crude oil prices will have on the supply, demand, and selling price for natural gas (LNG) in the importing country, with particular reference to escalation factors in the Applicant's LNG purchase contract, and similar contracts for other sources of supply; and

k) the supply and selling price of alternative sources of energy in international trade, e.g., heavy fuel oil, propane, and methanol, and an assessment of the impact that competition from these commodities will have on markets for natural gas (LNG) in the importing country.

The summary, Item 2 above, should identify for the Board's consideration, an estimate of:

l) the importing company's annual supply of natural gas (LNG) from each supply source to the year 2000;

m) the importing company's annual demand for natural gas (LNG) by market sector, residential, commercial, industrial, and power generation, to the year 2000;

n) the importing company's natural gas (LNG) supply and demand balance, indicating its need for supplies of Canadian natural gas (LNG); and

o) the alternative energy sources being consumed or that could be consumed by the importing company in direct competition with the proposed import of Canadian natural gas (LNG).

APPEARANCES

J.R. Smith, Q.C. M.A. Putman, Q.C. J.D. Ingram	- Alberta and Southern Gas Co. Ltd.
B.A. Crane, Q.C. D. Simmonds	- Canadian-Montana Pipe Line Company
D.B. Sabey, Q.C. M.A. Kelen	- Carter Energy Limited
H.R. Ward	- Columbia Gas Development of Canada Ltd.
H.M. Kay S.F. McAllister	- Consolidated Natural Gas Limited
R.C. Muir W.M. Smith J.F. Scott	- Dome Petroleum Limited
J.B. Ballem, Q.C. T.M. Hughes	- KannGaz Producers Ltd.
J.H. Farrell D.A. Quann	- Niagara Gas Transmission Limited
W.M. Elliott, Q.C. M.O. Laprairie	- Ocelot Industries Ltd.
F.R. Foran N.E. Hall K.F. Keeler	- Pan-Alberta Gas Ltd.
D.G. Hart, Q.C.	- ProGas Limited
R.J. Gibbs, Q.C. D.F. Robinson J. Stuart	- Rim Gas Ltd.
S. Carscallen P. Jull	- Sulpetro Limited
J.W.S. McOuat, Q.C. T. Dalgleish R.B. Cohen	- TransCanada PipeLines Limited
W.G. Burke-Robertson, Q.C. R.G. Hardy	- Transcontinental Gas Pipe Line Corporation

J.B. Jolley, Q.C. A. Mudryj	-	Union Gas Limited
J. Lutes	-	Westcoast Transmission Company Limited
A.S. Hollingworth J. Stein, Q.C. D.B. Reesor	-	Alberta Petroleum Marketing Commission
W.G. Burke-Robertson, Q.C. G. Hardy	-	Algonquin Gas Transmission Company
G.G. Baugh	-	Amoco Canada Petroleum Company Ltd.
J.B. Ballem, Q.C.	-	Blake Resources Ltd.
J.B. Ballem, Q.C.	-	Bonanza Oil & Gas Ltd.
C.K. Yates	-	Boundary Gas, Inc.
J.B. Ballem, Q.C. H. Ross	-	Bow Valley Industries Ltd.
M.F. Shoemaker	-	British Columbia Hydro and Power Authority
J.B. Ballem, Q.C. J.Donnelly	-	British Columbia Resources Investment Corporation
F.H. Ellins	-	Canadian Gas Association
R.J. Ludgate	-	Canadian Hunter Exploration Ltd.
H.R. Ward D.B. Macnamara M.M. Peterson	-	Canadian Petroleum Association
J.B. Ballem, Q.C.	-	Cherokee Resources Limited
J.B. Ballem, Q.C. H.J. Caine	-	Cheyenne Petroleum Corporation (N.P.L.)
J.B. Ballem, Q.C.	-	Cimarron Petroleum Ltd.
J.B. Ballem, Q.C. E. Beaman	-	Coho Resources Limited
J.B. Ballem, Q.C. G. Aitken	-	Colonial Oil & Gas Limited

J.B. Ballem, Q.C. R. Gould	-	Corrida Oils Ltd.
J.B. Ballem, Q.C.	-	Corvair Oils Ltd.
J.B. Ballem, Q.C. J. Hankinson	-	Edmunds Resources Ltd.
R.P.J. Gaetz	-	Esso Resources Canada Limited
J.B. Ballem, Q.C.	-	Embassy Resources Ltd.
J.B. Ballem, Q.C. J. Pendergast	-	Explorer Petroleum Corp.
Y. Brisson	-	Gaz Inter-Cité Québec Inc.
A. Bigué F. Bureau	-	Gaz Métropolitain, inc.
N. Kathuria	-	Great Lakes Gas Transmission Company
J.D. Anderson	-	Gulf Canada Resources Inc.
D. Case	-	ICG Brunswick Gas Ltd.
A.L. McLarty A.E. Potter	-	Independent Petroleum Association of Canada
P. Thompson, Q.C.	-	Industrial Gas Users Association
J.B. Ballem, Q.C. R. Braund	-	Intensity Resources Ltd.
J.B. Ballem, Q.C. H.J. Caine	-	KanEnergy Ltd.
J.B. Ballem, Q.C. R.L. Wickwire	-	Merland Explorations Limited
N. Kathuria	-	Michigan Wisconsin Pipe Line Company
H. Soloway, Q.C. W.T. Houston	-	Midwestern Gas Transmission Company
D.W. MacFarlane, Q.C. J.R. Much J. McWilliams	-	Mobil Oil Canada, Ltd.
J.H. Smellie	-	Natural Gas Pipeline Company of America

D.J. Roberts II F. Lasalle	- New England Conference of Public Utilities Commissioners, Inc. New York State Energy Office
J.J. Marshall	- Norcen Energy Resources Limited
J.B. Ballem, Q.C. W.K. Miller	- North Canadian Oils Limited
P.F. Scully	- Northern and Central Gas Corporation Limited
D. O'Brien, Jr. R. White	- Northern Border Pipeline Company
H.C. Rosenthal, Jr.	- Northern Natural Gas Company
E.B. McDougall D.K. Watkiss	- Northwest Alaskan Pipeline Company
G. Robichon	- Northwest Distributors CP National Corporation Cascade Natural Gas Corporation Intermountain Gas Company Northwest Natural Gas Company Southwest Gas Corporation Washington Natural Gas Company
E.B. McDougall D.K. Watkiss	- Northwest Pipeline Corporation
J. Hopwood, Q.C.	- NOVA, AN ALBERTA CORPORATION
J.B. Ballem, Q.C. E. Wyse D. Hall	- Omega Hydrocarbons Ltd.
J.B. Ballem, Q.C. R. Delbaere	- Orbit Oil & Gas Ltd.
M.P. Frawley	- Pacific Interstate Transmission Company
J.B. Ballem, Q.C. W. Haney	- Paloma Petroleum Ltd.
B. Jones	- PanCanadian Petroleum Limited
J.B. Ballem, Q.C. F. Thompson	- Pancontinental Oil Ltd.

J.B. Ballem, Q.C. G. Donaldson	-	Pangaea Petroleum Limited
A.R. O'Brien, Q.C. C.A. Conoley	-	Panhandle Eastern Pipe Line Company
J.B. Ballem, Q.C.	-	Passburg Petroleums Ltd.
J.B. Ballem, Q.C. G. Dann	-	Pembina Pipe Line Ltd.
J.W. Gallagher	-	Petro-Canada
H. Slade	-	Port Simpson Indian Band
J.B. Ballem, Q.C. T. Brooker	-	Ranchmen's Resources (1976) Ltd.
J. B. Ballem, Q.C. A. Higgins	-	Ravenna Resources Ltd.
J.B. Ballem, Q.C.	-	Rupertsland Resources Co. Ltd.
J.B. Ballem, Q.C.	-	Sceptre Resources Limited
A.P.G. Walker	-	Shell Canada Resources Limited
J.B. Ballem, Q.C.	-	Signalta Resources Limited
N. Roy	-	Société québécoise d'initiatives pétrolières
J.B. Ballem, Q.C. J. McDonald	-	Star Oil & Gas Ltd.
J.H. Farrell D.A. Quann	-	St. Lawrence Gas Company, Inc.
R.E. Wolf	-	Stone Petroleums Ltd. and Native Canadian Petroleum Association
J.B. Ballem, Q.C. F. Krukoff	-	Strom Resources Ltd.
H. Soloway, Q.C. W.T. Houston	-	Tennessee Gas Pipeline Company, a division of Tenneco Inc.
J. Zych	-	Texaco Canada Resources Ltd.

C.S. Brooker J.F. Weiler	-	Texas Eastern Transmission Corporation
G. Kane	-	Texas Gas Transmission Corporation
J.H. Farrell D.A. Quann	-	The Consumers' Gas Company Ltd.
C.S. Brooker J.F. Weiler	-	Transwestern Pipeline Company
J.B. Ballem, Q.C. G. McCartney N. Baiton	-	Turbo Resources Limited
W.O. Crain, Jr. G. Goolsby	-	United Gas Pipe Line Company and United Mid-Continent Pipeline Company
J.B. Ballem, Q.C.	-	Universal Explorations Ltd.
I.D. Laws G.T. Norgard	-	Wainoco Oil & Gas Limited
J.B. Ballem, Q.C.	-	Wellore Resources Ltd.
J.B. Ballem, Q.C. G. Fisher	-	Westgrowth Petroleums Ltd.
J.B. Ballem, Q.C. T. Allen	-	Zama Holdings Ltd.
J.B. Ballem, Q.C.	-	Zephyr Resources Ltd.
J.J. Arvay M.M. Moseley	-	Attorney General for the Province of British Columbia
M.J. Veniot	-	Province of Nova Scotia
J.M. Johnson, Q.C. E.J. Smith	-	Minister of Energy for Ontario
J. Giroux	-	Attorney General for the Province of Québec
W. Moull T. Allen	-	Saskatchewan Department of Mineral Resources
L.E. Smith A. Macdonald L. Meagher	-	National Energy Board

ABBREVIATIONS OF NAMES

"Alberta and Southern" or "A&S"	Alberta and Southern Gas Co. Ltd.
"AERCB"	Alberta Energy Resources Conservation Board
"AGBC"	Attorney General for the Province of British Columbia
"ANG"	Alberta Natural Gas Company Ltd.
"ANGTS"	Alaskan Natural Gas Transportation System
"ANR"	ANR Storage Company
"APMC"	Alberta Petroleum Marketing Commission
"Algonquin Gas"	Algonquin Gas Transmission Company
"Amoco Canada"	Amoco Canada Petroleum Company Ltd.
"B.C. Hydro"	British Columbia Hydro and Power Authority
"Boundary"	Boundary Gas, Inc.
"ICG"	ICG Transmission Limited
"ICG Brunswick"	ICG Brunswick Gas Ltd.
"CGA"	Canadian Gas Association
"CNG Fuel"	CNG Fuel Systems Ltd.
"CPA"	Canadian Petroleum Association
"Canadian Hunter"	Canadian Hunter Exploration Ltd.
"Canadian-Montana"	Canadian-Montana Pipe Line Company
"CPUC"	California Public Utilities Commission
"Carter"	Carter Energy Limited
"Columbia"	Columbia Gas Development of Canada Ltd.
"Columbia Transmission"	Columbia Gas Transmission Corporation
"Consolidated"	Consolidated Natural Gas Limited

"Consumers' Gas"	The Consumers' Gas Company Ltd.
"Dome"	Dome Petroleum Limited
"El Paso"	El Paso Natural Gas Company
"EOER"	Executive Office of Energy Resources
"ERA"	Economic Regulatory Agency
"Esso Resources"	Esso Resources Canada Limited
"Gaz Inter-Cité"	Gaz Inter-Cité Québec Inc.
"Gaz Métro"	Gaz Métropolitain, inc.
"FERC"	Federal Energy Regulatory Commission
"Foothills"	Foothills Pipe Lines (Yukon) Ltd.
"Great Lakes"	Great Lakes Gas Transmission Company
"Gulf"	Gulf Canada Resources Inc.
"Inter-City"	Inter-City Gas Corporation
"IGUA"	Industrial Gas Users Association
"IPAC"	Independent Petroleum Association of Canada
"KannGaz"	KannGaz Producers Ltd.
"Manitoba"	Attorney General for the Province of Manitoba
"Michigan Wisconsin"	Michigan Wisconsin Pipe Line Company
"Midwestern"	Midwestern Gas Transmission Company
"Mobil"	Mobil Oil Canada, Ltd.
"Montana Power"	The Montana Power Company
"NEB" or "the Board"	National Energy Board
"Natural Gas Pipe"	Natural Gas Pipeline Company of America
"Niagara Gas"	Niagara Gas Transmission Limited

"NIC"	NIC Resources Inc.
"Nissho Iwai"	Nissho Iwai Corporation
"Norcen"	Norcen Energy Resources Limited
"Northern & Central"	Northern and Central Gas Corporation Limited
"Northwest Alaskan"	Northwest Alaskan Pipeline Company
"Northern Border"	Northern Border Pipeline Company
"Northern Natural"	Northern Natural Gas Company
"Northwest Pipeline"	Northwest Pipeline Corporation
"Nova Scotia"	Province of Nova Scotia
"NOVA"	NOVA, AN ALBERTA CORPORATION
"Ocelot"	Ocelot Industries Ltd.
"Ontario"	Minister of Energy for Ontario
"Pacific Interstate"	Pacific Interstate Transmission Company
"Pan-Alberta"	Pan-Alberta Gas Ltd.
"PanCanadian"	PanCanadian Petroleum Limited
"Panhandle"	Panhandle Eastern Pipe Line Company
"PG&E"	Pacific Gas and Electric Company
"PGT"	Pacific Gas Transmission Company
"ProGas"	ProGas Limited
"Québec"	Attorney General for the Province of Québec
"Rim Gas"	Rim Gas Ltd.
"SOQUIP"	Société québécoise d'initiatives pétrolières
"SPC"	Saskatchewan Power Corporation
"Saskatchewan"	Saskatchewan Department of Mineral Resources

"Shell"	Shell Canada Resources Limited
"SoCal"	The Southern California Gas Company
"St.Lawrence Gas"	St. Lawrence Gas Company, Inc.
"Sulpetro"	Sulpetro Limited
"Tennessee"	Tennessee Gas Pipeline Company, a division of Tenneco Inc.
"Texaco"	Texaco Canada Resources Ltd.
"Texas Eastern" or "Tetco"	Texas Eastern Transmission Corporation
"Texas Gas"	Texas Gas Transmission Corporation
"TransCanada" or "TCPL"	TransCanada PipeLines Limited
"Transco"	Transcontinental Gas Pipe Line Corporation
"Transwestern"	Transwestern Pipeline Company
"Union Gas"	Union Gas Limited
"United"	United Gas Pipe Line Company
"United Mid-Continent"	United Mid-Continent Pipeline Company
"Vermont Gas"	Vermont Gas Systems, Inc.
"Westcoast" or "WTCL"	Westcoast Transmission Company Limited

ABBREVIATIONS OF TERMS

"ACQ"	-	Annual contract Quantity
"AFUDC"	-	Allowance for Funds Used During Construction
"ANGTS"	-	Alaskan Natural Gas Transportation System
"bcf"	-	Billion cubic feet (28.3 x $10^6 m^3$)
"B.E.R."	-	Beyond Economic Reach
"C.I.F."	-	Cost, Insurance and Freight
"CNG"	-	Compressed Natural Gas
"CPI"	-	Consumer Price Index
"EJ"	-	Exajoules (10^{18} joules)
"F.O.B."	-	Free on Board
"GJ"	-	Gigajoules (10^9 joules)
"GNE"	-	Gross National Expenditure
"GNP"	-	Gross National Product
"LNG"	-	Liquefied Natural Gas
"OPEC"	-	Organization of Petroleum Exporting Countries
"KW.h	-	Kilowatt hour (10^3 Watt hours)
"MJ"	-	Megajoules (10^6 joules)
"MMcf"	-	Million cubic feet
"m^3"	-	Cubic metre
"m^3/d"	-	Cubic metre per day
"NGPA"	-	Natural Gas Policy Act
"NEP"	-	National Energy Program

"10^3m^3"	-	Thousand cubic metres
"10^6m^3"	-	Million cubic metres
"10^9m^3"	-	Billion cubic metres
"$10^{12}m^3$"	-	Trillion cubic metres
"PJ"	-	Petajoules (10^{15} joules)
"SNG"	-	Synthetic Natural Gas
"TJ"	-	Terajoules (10^{12} joules)

REFERENCE REPORTS

"November 1979 Reasons for Decision"	National Energy Board - Reasons for Decision in the Matter of Applications under Part VI of the National Energy Board Act of Alberta and Southern Gas Co. Ltd., Canadian-Montana Pipe Line Company, Columbia Gas Development of Canada Ltd., Consolidated Natural Gas Ltd., Niagara Gas Transmission Limited, Pan-Alberta Gas Ltd., ProGas Limited, Sulpetro Limited, TransCanada PipeLines Limited, Westcoast Transmission Company Limited, - November 1979.
"June 1981 Report"	National Energy Board Canadian Energy Supply and Demand 1980-2000 June 1981.
"May 1982 Report or Phase I Decision"	National Energy Board Reasons for Decision in the Matter of Phase I - The Review Phase of the Gas Export Omnibus Hearing, 1982.
"AERCB - Report 82-18"	Alberta's Reserves of Crude Oil, Gas, Natural Gas Liquids, and Sulphur at 31 December 1981.

DEFINITIONS

Beyond Economic Reach Reserves	Those established reserves which because of size, geographic location or composition are not considered economically connectable to a pipeline at the present time.
C.I.F.	Cost, Insurance and freight charges are paid by the seller.
City-Gate Price	The average price charged by a natural gas transmission company for gas delivered at 100 percent load factor at the point of delivery, or sale, to a gas distribution company.
Conventional Areas	Those areas of Canada which have a long history of hydrocarbon production. Conventional areas are also referred to as non-frontier areas.
Deferred Reserves	Those quantities of established reserves which for a specific reason, usually because of involvement in a recycling or pressure maintenance project are not now available for market.
Deliverability	A general term used to refer to an actual or expected rate of natural gas production.
Established Reserves	Those reserves recoverable under current technology and present and anticipated economic conditions, specifically proved by drilling, testing or production, plus that judgement portion of contiguous recoverable reserves that are interpreted to exist, from geological, geophysical or similar information, with reasonable certainty.
Flat Life	That period of the producing life of natural gas during which production is maintained at a constant rate before decline commences.
F.O.B.	Free on board, price which does not include transportation of goods from the seller to the buyer.

Frontier Areas	Those areas of Canada which have a potential for but no history of production. These include the Mackenzie Delta - Beaufort Sea area, the Arctic Islands and the offshore areas.
Initial Established Reserves	Established reserves prior to the deduction of any production.
Part III hearings	Hearings held under Part III of the National Energy Board Act dealing with Certificates of Public Convenience and Necessity.
Part IV hearings	Hearings held under Part IV of the National Energy Board Act dealing with traffic, tolls and tariffs.
Monte Carlo Simulation	A statistical technique whereby an artificial probability distribution of possible events is randomly created.
Permeability	Permeability is a property of a porous medium and is a measure of the capacity of the medium to transmit fluids. (common unit of measurement is the millidarcy).
Primary Energy	This includes: a) energy use in the residential, commercial, industrial and transportation sectors; b) non-energy use of hydrocarbons (such as asphalt); c) energy use in energy supply industries (such as natural gas pipeline fuel); d) conversion losses in the transformation of energy forms (such as fossil fuels used to produce electricity); and e) electricity from nuclear and hydro sources assessed at the fossil fuel equivalent of 10.5 megajoules/kilowatt-hour.
Refinery-Gate Price	The delivered price of crude oil to a refinery, including all transportation charges to that point.
Remaining Established Reserves	Initial established reserves less cumulative production.
Reserves Additions	Incremental changes to established reserves resulting from the discovery of new pools and reserves appreciation.

Reserves Appreciation	Incremental change in established reserves resulting from extensions to existing pools and/or revisions to previous reserves estimates.
Secondary Energy	This includes: a) energy use in the residential, commercial, industrial and transportation sectors; and b) non-energy use of hydrocarbons.
TERMPOL	Standards for prevention of pollution at marine terminals.
Ultimate Potential	An estimate of the initial established reserves which will have become developed in an area by the time all exploratory and development activity has ceased, having regard for the geological prospects of that area and anticipated technology and economic conditions. Ultimate potential includes cumulative production, remaining established reserves and future additions through extensions and revisions to existing pools and the discovery of new pools.
Unconventional Reserves	Those reserves in very low permeability zones from which natural gas will not flow in commercial quantities without application of any technology other than that usually associated with gas well completion and production.

GUIDELINE TO COST-BENEFIT ANALYSIS FOR EXPORTS OF NATURAL GAS

Each applicant for a licence to export natural gas is required to submit a cost-benefit study, showing the estimated net benefits to Canada from exporting the requested quantity of natural gas, which should include, but not be limited to, the following:

I The economic benefits of exporting the natural gas over the requested term of the licence, including benefits from by-products where applicable.

II The incremental economic costs of exporting natural gas such as:

a) capital and operating costs of production;

b) capital and operating costs of transmission;

c) capital and operating costs of other associated facilities; and

d) cost to Canadians from having to use higher cost gas or other energy sources sooner than would otherwise be the case in the absence of exports.

The cost and benefit items should be provided on an annual basis along with the assumptions used to derive the costs and benefits. Applicants should indicate, through sensitivity analysis, the impact on the results of changes in key variables, such as natural gas export prices, and costs. For convenience, the Board suggests that the analysis be undertaken in 1981 constant dollars with results discounted to 1982.

To facilitate comparison among applications, the Board requests that applicants undertake one scenario using 1981 constant dollars with results discounted to 1982 at a discount rate of ten percent per annum and the present natural gas export price held constant in real terms over the life of the project. The cost and benefit items should be provided on an annual basis along with the assumptions used to derive the costs and benefits.

For this case, sensitivity analyses should be performed as follows:

(i) discount rates of 5 and 15 percent; and

(ii) natural gas export prices increasing at two percent per annum, and decreasing at two percent per annum.

Applicants may wish to consult the Board's November 1979 Reasons for Decision arising out of the 1979 Omnibus Gas Export Hearing, and particularly Appendix F.